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 001-33366

Cheniere Energy Partners, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**20-5913059**
(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 Units Representing Limited Partner Interests	**CQP**	**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 units held by non-affiliates of the registrant was approximately $1.8 billion as of June 30, 2023.

As of February 16, 2024, the registrant had 484,040,623 common units outstanding.

Documents incorporated by reference: **None**

CHENIERE ENERGY PARTNERS, L.P.

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DEFINITIONS

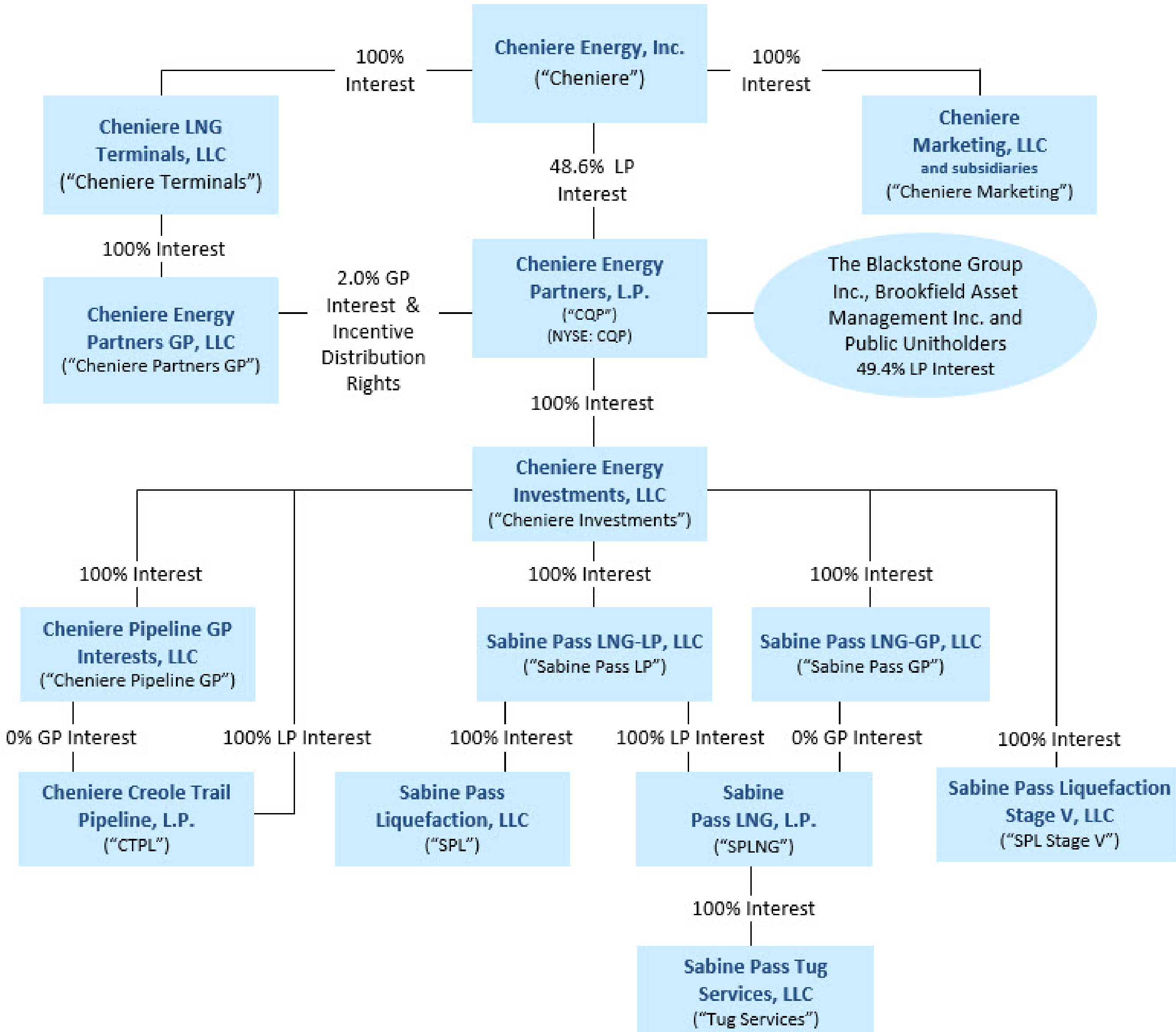
As used in this annual report, the terms listed below have the following meanings:

Common Industry and Other Terms

ASU	Accounting Standards Update
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Bcf/yr	billion cubic feet per year
Bcfe	billion cubic feet equivalent
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 "CQP," the "Partnership," "we," "us" and "our" refer to Cheniere Energy Partners, L.P. and its consolidated subsidiaries.

CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING STATEMENTS

This annual report contains certain statements that are, or may be deemed to be, "forward-looking statements." 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 regarding our ability to pay distributions to our unitholders;
- statements regarding our expected receipt of cash distributions from SPLNG, SPL or CTPL;
- statements that we expect to commence or complete construction of our proposed LNG terminal, liquefaction facility, pipeline facility 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 regarding our future sources of liquidity and cash requirements;
- statements relating to the construction of our Trains, 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, including the financing of such Trains;
- 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;
- 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

We are a publicly traded Delaware limited partnership formed in 2006 by Cheniere. 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 own 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, which has six operational Trains, for a total production capacity of approximately 30 mtpa of LNG (the **"Liquefaction Project"**). The Sabine Pass LNG Terminal also has operational regasification facilities that include five LNG storage tanks with aggregate capacity of approximately 17 Bcfe, 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 a 94-mile natural gas supply pipeline through our subsidiary, CTPL, that interconnects the Sabine Pass LNG Terminal to several interstate and intrastate pipelines (the **"Creole Trail Pipeline"**).

Our long-term customer arrangements form the foundation of our business and provide us with significant, stable, long-term cash flows. We have contracted most 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 agreement, we have contracted approximately 85% of the total anticipated production from the Liquefaction Project with approximately 14 years of weighted average remaining life as of December 31, 2023, excluding volumes that are contractually subject to additional liquefaction capacity beyond what is currently in construction or operation.

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 Project 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 a significant land position at the Sabine Pass LNG Terminal, which provides opportunity for further liquefaction capacity expansion. In May 2023, certain of our subsidiaries entered the pre-filing review process with the FERC under the National Environmental Policy Act (**"NEPA"**) for an expansion adjacent to the Liquefaction 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 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 a positive FID is made.

Our Business Strategy

Our primary business strategy is to develop, construct and operate assets to meet our long-term customers' energy demands. We plan to implement our strategy by:

- safely, efficiently and reliably operating and maintaining our assets, including our Trains;
- procuring natural gas and pipeline transport capacity to our facility;
- commencing commercial delivery for our long-term SPA customers, of which we have initiated for nine of eleven third party long-term SPA customers as of December 31, 2023;
- continuing to secure long-term customer contracts to support our planned expansion, including the FID of potential expansion projects;
- maximizing the production of LNG to serve our customers and generating steady and stable revenues and operating cash flows;
- optimizing the Liquefaction Project by leveraging existing infrastructure;
- maintaining a prudent and cost-effective capital structure; and
- strategically identifying actionable and economic environmental solutions.

Our Business

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

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 of our subsidiaries 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 FERC to site, construct and operate the Trains at the Liquefaction 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 Liquefaction 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 Liquefaction 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.

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	23%	22%	24%
Korea Gas Corporation	16%	15%	17%
GAIL (India) Limited	16%	15%	17%
Naturgy LNG GOM, Limited	15%	15%	16%
TotalEnergies Gas & Power North America, Inc.	11%	10%	11%

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 17—Customer Concentration of our Notes to Consolidated Financial Statements.

Governmental Regulation

The Sabine Pass LNG Terminal and the Creole Trail Pipeline 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 the Sabine Pass LNG Terminal, the import or export of LNG and the purchase and transportation of natural gas in interstate commerce through the Creole Trail Pipeline are highly regulated activities subject to the jurisdiction of the FERC pursuant to the Natural Gas Act of 1938, as amended (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 pipeline is not permitted to unduly discriminate or grant undue preference as to rates or the terms and conditions of service to any shipper, including its own marketing affiliate. 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 emissions (**"GHG"**) 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 the Sabine Pass LNG Terminal, 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 May 2023, certain of our subsidiaries 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 the Sabine Pass LNG Terminal and the Creole Trail Pipeline. 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 the Sabine Pass LNG Terminal and Creole Trail Pipeline. For example, throughout the life of the Sabine Pass LNG Terminal and the Creole Trail Pipeline, 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 and Expansion Project.* 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. We have no projects pending non-FTA export approval with the DOE at this time, although 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* section above for FERC and DOE approved volumes on our existing Liquefaction Project.

Pipeline and Hazardous Materials Safety Administration

The Sabine Pass LNG Terminal as well as the Creole Trail 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 requires 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 and the Louisiana Department of Environmental Quality (the **"LDEQ"**).

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 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.

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.

Environmental Regulation

The Sabine Pass LNG Terminal is 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

The Sabine Pass LNG Terminal is 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 at the Sabine Pass LNG Terminal.

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 the Sabine Pass LNG Terminal 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 to have a material adverse effect on our operations, financial condition or results of operations.

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

The siting and construction of the Sabine Pass LNG Terminal 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). 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

The Sabine Pass LNG Terminal is 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). 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 the Sabine Pass LNG Terminal or the Creole Trail Pipeline adversely affect 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 at the Sabine Pass LNG Terminal.

Market Factors and Competition

Market Factors

Our ability to enter into additional long-term SPAs to underpin the development of additional Trains 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 European Union 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 Project, as well as our proposed expansion at Sabine Pass is 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 agreement, we have contracted approximately 85% of the total anticipated production from the Liquefaction Project, with approximately 14 years of weighted average remaining life as of December 31, 2023, excluding volumes that are contractually subject to additional liquefaction capacity beyond what is currently in construction or operation. Customers are required to pay a fixed fee with respect to the contracted volumes, irrespective of their election to cancel or suspend deliveries of LNG cargoes.

Competition

Despite the long term nature of our SPAs, when SPL needs to replace or amend any existing SPA or enter into new SPAs, SPL will compete on the basis of price per contracted volume of LNG with other natural gas liquefaction projects throughout the world, including our affiliate Corpus Christi Liquefaction, LLC (**"CCL"**), which operates three Trains at a natural gas liquefaction facility near Corpus Christi, Texas. Revenues associated with any incremental volumes of the Liquefaction Project, including those made available to Cheniere Marketing, 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, Cheniere published *The Power of Connection*, its fourth Corporate Responsibility (**"CR"**) report, which details Cheniere's approach and progress on ESG matters. Cheniere's CR report is available at www.cheniere.com/our-responsibility/reporting-center. Information on Cheniere's website, including the CR report, is not incorporated by reference into this Annual Report on Form 10-K.

Cheniere's 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, Cheniere has 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. Cheniere 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, Cheniere commenced providing Cargo Emissions Tags (**"CE Tags"**) to its 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.

Employees

We have no employees. We rely on our general partner to manage all aspects of the development, construction, operations, maintenance and management of the Sabine Pass LNG Terminal and to conduct our business. Because our general partner has no employees, it relies on subsidiaries of Cheniere to provide the personnel necessary to allow it to meet its management obligations to us, SPLNG, SPL and CTPL. As of December 31, 2023, Cheniere and its subsidiaries had 1,605 full-time employees, including 501 employees who directly supported the Sabine Pass LNG Terminal operations. See Note 14—Related Party Transactions of our Notes to Consolidated Financial Statements for a discussion of the services agreements with subsidiaries of Cheniere.

Available Information

Our common units have been publicly traded since March 21, 2007 and are traded on the New York Stock Exchange under the symbol "CQP." 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 unitholder, 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 Partners, L.P, 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 and other information regarding issuers.

ITEM 1A. RISK FACTORS

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. 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 operations 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;
- Risks Relating to Regulations;
- Risks Relating to Our Relationship with Our General Partner;
- Risks Relating to an Investment in Us and Our Common Units; and
- Risks Relating to Tax Matters.

Risks Relating to Our Financial Matters

An inability to source capital to supplement our available cash resources and existing revolving 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, $575 million of cash and cash equivalents, $56 million of restricted cash and cash equivalents, a total of $1.7 billion of available commitments under our credit facilities and $16.0 billion of total debt outstanding (before unamortized discount and debt issuance costs). SPL and CQP 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 we anticipate drawing on current committed facilities and/or incurring additional debt to finance the construction of the SPL Expansion Project if a positive FID is made. 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 customer 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 11 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 to us under certain circumstances, which may limit our ability to pay or increase distributions to our unitholders and could materially and adversely affect the market price of our common units.

The agreements governing our subsidiaries' indebtedness restrict payments that our subsidiaries can make to 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.

Our subsidiaries' inability to pay distributions to us as a result of the foregoing restrictions in the agreements governing their indebtedness may inhibit our ability to pay or increase distributions to our unitholders, 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 3—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 $1.1 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 agreement in force.

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 zero and $35 million, respectively, which are included in margin deposits in our Consolidated Balance Sheets.

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

In addition to restrictions on the ability of us and SPL to make distributions or incur additional indebtedness, the agreements governing SPL's indebtedness also contain various other covenants that may prevent them from engaging in beneficial transactions, including limitations on their 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 its assets; and
- enter into sale and leaseback transactions.

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

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 Project, damage to our Liquefaction Project 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. In August 2020, SPL entered into an arrangement with its affiliate to provide the ability, in limited circumstances, to potentially fulfill commitments to LNG buyers from the other facility in the event operational conditions impact operations at the Sabine Pass LNG Terminal or at its affiliate's terminal. During the year ended December 31, 2021, eight TBtu was loaded at affiliate facilities pursuant to this agreement. 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 terminal 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 our other facilities. Our LNG terminal infrastructure and LNG facility located in or near 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 pipeline 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 Project and to and from the Creole Trail Pipeline. 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 Project, damage to our Liquefaction Project 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 Project 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.

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 the Sabine Pass LNG Terminal and the operation of the Creole Trail Pipeline 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.

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 exports 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 Project 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 Project 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 Project in certain markets. The cost of LNG supplies from the United States, including the Liquefaction Project, 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 agreement approximately 85% of the total anticipated production from the Liquefaction Project with approximately 14 years of weighted average remaining life as of December 31, 2023, excluding 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 Project is 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 Project are diverse and include, among others:

- increases in worldwide LNG production capacity and availability of LNG for market supply;
- increases in demand for LNG but at levels below those required to maintain current price equilibrium with respect to supply;
- increases in the cost to supply natural gas feedstock to our Liquefaction Project;
- decreases in the cost of competing sources of natural gas or 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 Project, 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 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 Project. For example, in 2021 Colonial Pipeline suffered a ransomware attack that led to the complete shutdown of its pipeline system for six days. Should multiple of the third party pipelines which supply our Liquefaction Project suffer similar concurrent attacks, the Liquefaction Project 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.

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

Our facilities at the Sabine Pass 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 pipeline 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, our LNG terminal, including the Liquefaction Project, the SPL Expansion Project and other facilities, as well as the 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 Liquefaction Project, as well as orders under Section 7 of the NGA authorizing the construction and operation of the Creole Trail Pipeline. In May 2023, certain of our subsidiaries entered the pre-filing review process with the FERC under the NEPA for the SPL Expansion Project. To date, the DOE has also issued orders under Section 4 of the NGA authorizing SPL 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. We have no projects pending non-FTA export approval with the DOE at this time, although 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 pipeline 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 Creole Trail Pipeline and its FERC gas tariff are subject to FERC regulation. If we fail to comply with such regulation, we could be subject to substantial penalties and fines.

The Creole Trail Pipeline is 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 Creole Trail Pipeline 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 Creole Trail Pipeline 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 terminal, docks and pipeline, 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 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. 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 the methane emissions charge 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 the Sabine Pass LNG Terminal or climate policies of destination countries in relation to their obligations under the Paris Agreement or other national 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.

Risks Relating to Our Relationship with Our General Partner

We are entirely dependent on our general partner, Cheniere, including employees of Cheniere and its subsidiaries, for key personnel, and the unavailability of skilled workers or Cheniere's failure to attract and retain qualified personnel could adversely affect us. In addition, changes in our general partner's senior management or other key personnel could affect our business results.

As of December 31, 2023, Cheniere and its subsidiaries had 1,605 full-time employees, including 501 employees who directly supported the Sabine Pass LNG Terminal operations. We have contracted with subsidiaries of Cheniere to provide the personnel necessary for the operation, maintenance and management of the Sabine Pass LNG Terminal, the Creole Trail Pipeline and construction and operation of the Liquefaction Project. We depend on Cheniere's subsidiaries hiring and retaining personnel sufficient to provide support for the Sabine Pass LNG Terminal. Cheniere competes with other liquefaction projects in the United States and globally, 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 also compete with any other project Cheniere is developing, including its liquefaction project at Corpus Christi, Texas, for the time and expertise of Cheniere's personnel. Further, we and Cheniere face competition for these highly skilled employees in the immediate vicinity of the Sabine Pass LNG Terminal and more generally from the Gulf Coast hydrocarbon processing and construction industries.

The executive officers of our general partner are officers and employees of Cheniere and its affiliates. We do not maintain key person life insurance policies on any personnel, and our general partner does not have any employment contracts or other agreements with key personnel binding them to provide services for any particular term. The loss of the services of any of these individuals could have a material adverse effect on our business. In addition, our future success will depend in part on our general partner's ability to engage, and Cheniere's ability to attract and retain, additional qualified personnel.

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 to attract and retain qualified personnel and could require an increase in the wage and benefits packages that are offered, 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.

Our general partner and its affiliates have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to the detriment of us and our unitholders.

Cheniere owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Some of our general partner's directors are also directors of Cheniere, and certain of our general partner's officers are officers of Cheniere. Therefore, conflicts of interest may arise between Cheniere and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of us and our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires Cheniere to pursue a business strategy that favors us. Cheniere's directors and officers have a fiduciary duty to make these decisions in favor of the owners of Cheniere, which may be contrary to our interests:
- our general partner controls the interpretation and enforcement of contractual obligations between us, on the one hand, and Cheniere, on the other hand, including provisions governing administrative services and acquisitions;
- our general partner is allowed to take into account the interests of parties other than us, such as Cheniere and its affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to us and our unitholders;
- our general partner has limited its liability and reduced its fiduciary duties under the partnership agreement, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty;
- Cheniere is not limited in its ability to compete with us. Cheniere is not restricted from competing with us and is free to develop, operate and dispose of, and is currently developing, LNG facilities, pipelines and other assets without any obligation to offer us the opportunity to develop or acquire those assets;
- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuances of additional partnership securities, and the establishment, increase or decrease in the amounts of reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

We also have agreements to compensate and to reimburse expenses of affiliates of Cheniere. All of these agreements involve conflicts of interest between us, on the one hand, and Cheniere and its other affiliates, on the other hand. In addition, Cheniere is currently operating three Trains at a natural gas liquefaction facility near Corpus Christi, Texas and CCL has entered into fixed price SPAs with third-parties for the sale of LNG from this natural gas liquefaction facility, and may continue to enter in commercial arrangements with respect to this liquefaction facility that might otherwise have been entered into with respect to any of our future Trains.

We have or will have numerous contracts and commercial arrangements with Cheniere and its affiliates, including future SPAs, transportation, interconnection, marketing and gas balancing arrangements, as well as servicing and other agreements and arrangements that cannot now be anticipated. In those circumstances where additional contracts with Cheniere and its affiliates may be necessary or desirable, additional conflicts of interest may be involved.

In the event Cheniere favors its interests over our interests, we may have less available cash to make distributions on our units than we otherwise would have if Cheniere had favored our interests.

Risks Relating to an Investment in Us and Our Common Units

Our partnership agreement limits our general partner's fiduciary duties to our unitholders and restricts the remedies available to our unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, the exercise of its rights to transfer or vote the units it owns, the exercise of its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as general partner, as long as it acted in good faith, meaning that it believed the decision was in the best interests of our partnership, including in resolution of conflicts of interest;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us;
- provides that our general partner, its affiliates and their officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or those other persons acted in bad faith or engaged in fraud, willful misconduct or, in the case of a criminal matter, acted with knowledge that such conduct was criminal; and
- provides that in resolving conflicts of interest, it will be presumed that in making its decision the conflicts committee or the general partner acted in good faith, and in any proceedings brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

By purchasing a common unit, a unitholder will become bound by the provisions of our partnership agreement, including the provisions described above.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which our common units trade.

Unlike the holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our unitholders have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen entirely by affiliates of Cheniere. As a result, the price at which the common units trade could be diminished because of the absence or reduction of a control premium in the trading price.

The vote of the holders of at least 66 2/3% of all outstanding common units (including any units owned by our general partner and its affiliates), voting together as a single class is required to remove our general partner. Cheniere owns 48.6% of our outstanding common units, but it is contractually prohibited from voting our units that it holds in favor of the removal of our general partner.

Additionally, our partnership agreement restricts unitholders' voting rights by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner and its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Any change of our general partner or the replacement of the board of directors or officers of our partnership, which can occur without the consent of our unitholders, can impact our future operations and have an adverse impact on the trading price of our common units.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective ownership interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices and thereby influence the decisions taken by the board of directors and officers. Any change in our general partner or the replacement of the board of directors or officers of our partnership can impact our future operations and have an adverse impact on the trading price of our common units.

Our partnership agreement prohibits a unitholder (other than our general partner and its affiliates) who acquires 15% or more of our limited partner units without the approval of our general partner from engaging in a business combination with us for three years unless certain approvals are obtained. This provision could discourage a change of control that our unitholders may favor, which could negatively affect the price of our common units.

Our partnership agreement effectively adopts Section 203 of the General Corporation Law of the State of Delaware (**"DGCL"**). Section 203 of the DGCL as it applies to us prevents an interested unitholder defined as a person (other than our general partner and its affiliates) who owns 15% or more of our outstanding limited partner units from engaging in business combinations with us for three years following the time such person becomes an interested unitholder unless certain approvals are obtained. Section 203 broadly defines "business combination" to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. This provision of our partnership agreement could have an anti-takeover effect with respect to transactions not approved in advance by our general partner, including discouraging takeover attempts that might result in a premium over the market price for our common units.

Our unitholders may not have limited liability if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for contractual obligations of the partnership that are expressly made without recourse to the general partner. We are organized under Delaware law, and we conduct business in other states. As a limited partner in a partnership organized under Delaware law, holders of our common units could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders as a group to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other action under our partnership agreement constituted participation in the "control" of our business. In addition, limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in many jurisdictions.

Our unitholders may have liability to repay distributions wrongfully made.

Under certain circumstances, our unitholders may have to repay amounts wrongfully distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that, for a period of three years from the date of the impermissible distribution, partners who received such a distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the partnership for the distribution amount. Liabilities to partners on account of their partner interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Affiliates of our general partner or affiliates of Blackstone Inc. ("Blackstone") or Brookfield Asset Management Inc. ("Brookfield") may sell limited partner units, which sales could have an adverse impact on the trading price of our common units.

Sales by us or any of our affiliated unitholders or affiliates of Blackstone of a substantial number of our common units, or the perception that such sales might occur, could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. As of December 31, 2023, Cheniere owned approximately 239.9 million of our common units. We also filed a registration statement for the resale of 202,450,687 common units owned by Blackstone and its affiliates in 2017. Any sales of these units could have an adverse impact on the price of our common units.

Risks Relating to Tax Matters

Our tax treatment depends on our status as a partnership for federal income tax purposes, and our not being subject to a material amount of entity-level taxation by individual states. If we were treated as a corporation for federal income tax purposes or if we were to become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. Despite the fact that we are a limited partnership under Delaware law, we will be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate and would likely pay state and local income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distributions to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of such taxes on us in jurisdictions in which we operate, or to which we may expand our operations, may substantially reduce the cash available for distribution to our unitholders and, therefore, negatively impact the value of an investment in our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the initial quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. Although final Treasury Regulations allow publicly traded partnerships to use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders, such tax items must be prorated on a daily basis and these regulations do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to successfully challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful Internal Revenue Service ("IRS") contest of the federal income tax positions that we take, may adversely impact the market for our common units, and the costs of any contest will be borne by our unitholders and our general partner.

The IRS may adopt positions that differ from the positions that we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions that we take. A court may not agree with some or all of the positions that we take. Any contest with the IRS may adversely impact the taxable income reported to our unitholders and the income taxes they are required to pay. As a result, any such contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

For tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under applicable rules, our general partner may pay such amounts directly to the IRS or, if we are eligible, elect to issue a revised Schedule K-1 to each unitholder with respect to an audited and adjusted return. No assurances can be made that such election will be practical, permissible, or effective in all circumstances. As a result, our current unitholders may bear some or all of the economic burden resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced.

Our unitholders may be required to pay taxes on their share of our taxable income even if they do not receive any cash distributions from us.

Our unitholders are required to pay any U.S. federal income taxes and, in some cases, state and local income taxes, on their share of our taxable income irrespective of whether they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability attributable to their share of our taxable income.

Tax gain or loss on the disposition of our common units could be different than expected.

If our unitholders sell any of their common units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of the unitholders' allocable share of our net taxable income decrease the unitholders' tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to the unitholder if they sell such units at a price greater than their tax basis in those units, even if the price received is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income due to the potential recapture items, including depreciation recapture. In addition, because the amount realized may include a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investments in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), raises issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our common units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). A unitholder's share of our income, gain, loss and deduction, and any gain from the sale or disposition of our common units will generally be considered to be "effectively connected" with a U.S. trade or business and subject to U.S. federal income tax. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a common unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that common unit.

Moreover, upon the sale, exchange or other disposition of a common unit by a non-U.S. unitholder, withholding at a rate of 10% may be required on the amount realized unless the disposing unitholder certifies that it is not a foreign person. Treasury regulations provide that the "amount realized" on a transfer of an interest in a publicly traded partnership, such as our common units, will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the unitholder. Quarterly distributions made to our non-U.S. unitholders will also be subject to withholding under these rules to the extent a portion of a distribution is attributable to an amount in excess of our cumulative net income that has not previously been distributed. We intend to treat all of our distributions as being in excess of our cumulative net income for such purposes and subject to the additional 10% withholding tax. For transfers of, or distributions on, interests in a publicly traded partnership occurring before January 1, 2023, and after that date, if effected through a broker, the obligation to withhold is imposed on the transferor's broker. Non-U.S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

Our unitholders will likely be subject to state and local taxes and return filing requirements as a result of an investment in our common units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if the unitholder does not live in any of those jurisdictions. Our unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Furthermore, our unitholders may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own property or conduct business in additional states or foreign countries that impose a personal tax or an entity level tax. Unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of our unitholders to file all United States federal, state and local tax returns.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates ourselves using a methodology based on the market value of our common units as a means to determine the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Cyberattacks represent a potentially significant risk to the Partnership and its industry. We have implemented policies and procedures that are intended to manage and reduce this risk, including those managed by affiliates of Cheniere through our service agreements with them, as further discussed in Note 14—Related Party Transactions of our Notes to Consolidated Financial Statements.

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 the Partnership 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 and Cheniere 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. Cheniere maintains a training program to help its personnel identify and assist in mitigating cybersecurity and data security risks. Cheniere's employees and the board of directors of our general partner participate in annual training, user awareness campaigns and additional issue-specific training as needed. Cheniere also provides annual training for certain contractors who have access to its information technology networks.

With respect to third party service providers, Cheniere's 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 Cheniere's data, including personal information, for purposes other than to provide services to us, except as required by applicable law. Cheniere also seeks to negotiate contractual requirements which compel our service providers to notify us of information security incidents occurring on their systems which may affect Cheniere's 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

We rely on Cheniere's cybersecurity leadership team, which consists of its Director and Chief Information Security Officer (**"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. Cheniere's 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 the board of directors of our general partner and Audit Committee deliberations throughout the year. The board of directors of our general partner 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 Cheniere's 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, Cheniere's 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 Project, 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 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 UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units trade on the New York Stock Exchange under the symbol "CQP", and previously traded on the NYSE American or its predecessors under the symbol "CQP" from our initial public offering on March 21, 2007 through February 3, 2024. As of February 16, 2024, we had 484.0 million common units outstanding held by 10 record owners.

We consider cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors.

Cash Distribution Policy

Our cash distribution policy is consistent with the terms of our partnership agreement, which requires that we distribute all of our available cash quarterly.

General Partner Units and Incentive Distribution Rights ("IDRs")

IDRs represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus in excess of the initial quarterly distribution. Our general partner currently holds the IDRs but may transfer these rights separately from its general partner interest.

Assuming we do not issue any additional classes of units that are paid distributions and our general partner maintains its 2% interest, if we have made distributions to our unitholders from operating surplus in an amount equal to the initial quarterly distribution for any quarter, assuming no arrearages, then we will distribute any additional available cash from operating surplus for that quarter among the unitholders and our general partner as follows:

		Marginal Percentage Interest Distributions	
	Total Quarterly Distribution Target Amount	Common and Subordinated Unitholders	General Partner
Initial quarterly distribution	$0.425	98%	2%
First Target Distribution	Above $0.425 up to $0.489	98%	2%
Second Target Distribution	Above $0.489 up to $0.531	85%	15%
Third Target Distribution	Above $0.531 up to $0.638	75%	25%
Thereafter	Above $0.638	50%	50%

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 a limited partnership formed by Cheniere to provide clean, secure and affordable LNG to integrated energy companies, utilities and energy trading companies around the world. We own the natural gas liquefaction and export facility at Sabine Pass, Louisiana. 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 agreement, we have contracted approximately 85% of the total anticipated production from the Liquefaction Project with approximately 14 years of weighted average remaining life as of December 31, 2023, excluding 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. 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.

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, Cheniere 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 Cheniere making a positive FID on the first train of the SPL Expansion Project or us unilaterally waiving that requirement.

- In May 2023, certain of our subsidiaries 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 Energy Inc. to provide the front end engineering and design work on the project.
- On January 2, 2023, Corey Grindal, formerly Executive Vice President, Worldwide Trading, was promoted to Executive Vice President and Chief Operating Officer of Cheniere Partners GP.

Operational

- As of February 16, 2024, approximately 2,410 cumulative LNG cargoes totaling approximately 165 million tonnes of LNG have been produced, loaded and exported from the Liquefaction Project.

Financial

- We closed the following debt transactions:
    - In September and November 2023, SPL redeemed an aggregate of $100 million of its 5.750% Senior Secured Notes due 2024 (the **"2024 SPL Senior Notes"**).
    - In June 2023, we 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 2024 SPL Senior Notes in July 2023.
    - In June 2023, we 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.
- In August 2023, Fitch Ratings (**"Fitch"**) upgraded SPL's senior secured debt and issuer credit ratings from BBB to BBB+ with a stable outlook.
- In February 2023, S&P Global Ratings (**"S&P"**) upgraded its issuer credit rating of SPL from BBB to BBB+ with a stable outlook.
- We declared aggregate distributions of $4.12 per common unit for the year ended December 31, 2023. On January 26, 2024, with respect to the fourth quarter of 2023, we declared a cash distribution of $1.035 per common unit to unitholders of record as of February 7, 2024 and the related general partner distribution that was paid on February 14, 2024. These distributions consist of a base amount of $0.775 per unit and a variable amount of $0.260 per unit.

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 Project reached approximately 30 million tonnes in aggregate, representing over 34% 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 Cheniere's 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

(in millions, except per unit data)	Year Ended December 31, 2023	2022	Variance
Revenues			
LNG revenues	$ 6,991	$ 11,507	$ (4,516)
LNG revenues—affiliate	2,475	4,568	(2,093)
Regasification revenues	135	1,068	(933)
Other revenues	63	63	—
Total revenues	9,664	17,206	(7,542)
Operating costs and expenses			
Cost of sales (excluding items shown separately below)	2,721	11,887	(9,166)
Cost of sales—affiliate	22	213	(191)
Operating and maintenance expense	879	757	122
Operating and maintenance expense—affiliate	166	166	—
Operating and maintenance expense—related party	62	72	(10)
General and administrative expense	10	5	5
General and administrative expense—affiliate	89	92	(3)
Depreciation and amortization expense	672	634	38
Other	6	—	6
Other—affiliate	1	—	1
Total operating costs and expenses	4,628	13,826	(9,198)
Income from operations	5,036	3,380	1,656
Other income (expense)			
Interest expense, net of capitalized interest	(823)	(870)	47
Loss on modification or extinguishment of debt	(6)	(33)	27
Interest and dividend income	46	21	25
Other income, net	1	—	1
Total other expense	(782)	(882)	100
Net income	$ 4,254	$ 2,498	$ 1,756
Basic and diluted net income per common unit	$ 6.95	$ 3.27	$ 3.68

Volumes loaded and recognized from the Liquefaction Project

	Year Ended December 31, 2023	2022	Variance
LNG volumes loaded and recognized as revenues (in TBtu)	1,536	1,520	16

Net income

The increase of $1.8 billion in net income between the years ended December 31, 2023 and 2022 was primarily attributable to the favorable variance of $3.2 billion from changes in fair value and settlements of derivatives. During the year ended December 31, 2023, we recognized gains of $1.8 billion due to non-cash favorable changes in fair value of the IPM agreement with Tourmaline Oil Marketing Corp. (the **"Tourmaline IPM Agreement"**) as a result of lower volatility in international gas prices and declines in international forward commodity curves, as compared to a loss of $757 million in the year ended December 31, 2022 following the assignment of the Tourmaline IPM Agreement to SPL from Corpus Christi Liquefaction Stage III, LLC (**"CCL Stage III"**) in March 2022. The 2022 loss following the assignment was primarily attributed to SPL's lower credit risk profile relative to that of CCL Stage III, resulting in a higher derivative liability given reduced risk of SPL's own nonperformance and shifts in the international forward commodity curve. The increase was partially offset by a reduction in LNG revenues, net of cost of sales and excluding the aforementioned effect of derivatives, of $492 million between the years ended December 31, 2023 and 2022, which was attributable to lower margins on LNG delivered. The remaining offsetting variance is primarily attributable to a decrease in our regasification revenues primarily as a result of the early termination of one of our TUA agreements in December 2022.

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

Revenues

The $7.5 billion decrease in revenues between the years ended December 31, 2023 and 2022 was primarily attributable to:

- $6.7 billion decrease in revenues due to lower pricing per MMBtu, from decreased Henry Hub pricing; and
- $933 million decrease in regasification revenues 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

The $9.2 billion decrease in operating costs and expenses between the years ended December 31, 2023 and 2022 was primarily attributable to:

- $6.1 billion decrease in cost of sales excluding the effect of derivative changes described below, primarily as a result of $6.0 billion decrease in cost of natural gas feedstock largely due to lower U.S. natural gas prices; and
- $3.2 billion favorable variance from changes in fair value and settlements of derivatives included in cost of sales, from a loss of $1.2 billion in the year ended December 31, 2022 to a gain of $2.1 billion in the year ended December 31, 2023, primarily due to decreased international gas prices resulting in non-cash favorable changes in fair value of our commodity derivatives indexed to such prices, specifically associated with the Tourmaline IPM Agreement as discussed above under *Net income.*

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 are utilized to manage our exposure to commodity-related marketing and price risks and 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 8—Derivative

Instruments of our Notes to Consolidated Financial Statements, the fair value of our Liquefaction Supply Derivatives incorporates 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 $148 million corresponding to 13 TBtu attributable to the sale of commissioning cargoes from Train 6 of the Liquefaction 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 offerings by us or our subsidiaries and equity offerings by us. 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	$ 575
Restricted cash and cash equivalents designated for the Liquefaction Project	56
Available commitments under our credit facilities (1):	
SPL Revolving Credit Facility	720
CQP Revolving Credit Facility	1,000
Total available commitments under our credit facilities	1,720
Total available liquidity	$ 2,351

(1) 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, we and our subsidiary SPL operate with independent capital structures. Certain restrictions under debt instruments executed by SPL limit its ability to distribute cash, including the following:

- SPL is 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 Project and other restricted payments. In addition, SPL's operating costs are managed by subsidiaries of Cheniere under affiliate agreements, which may require SPL to advance cash to the respective affiliates; and
- SPL is restricted by affirmative and negative covenants included in certain of its debt agreements in its ability to make certain payments, including distributions, unless specific requirements are satisfied.

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

Supplemental Guarantor Information

The 2033 CQP Senior Notes are jointly and severally guaranteed by each of our current and future subsidiaries who guarantee the CQP Revolving Credit Facility and the $1.5 billion of 4.500% Senior Notes due 2029, $1.5 billion of 4.000% Senior Notes due 2031 and $1.2 billion of 3.25% Senior Notes due 2032 (together with the 2033 CQP Senior Notes, the **"CQP Senior Notes"**) are jointly and severally guaranteed by each of our subsidiaries other than SPL and, subject to certain conditions governing its guarantee, Sabine Pass LP (each a **"Guarantor"** and collectively, the **"CQP Guarantors"**).

The CQP Guarantors' guarantees are full and unconditional, subject to certain release provisions including (1) the sale, disposition or transfer (by merger, consolidation or otherwise) of the capital stock or all or substantially all of the assets of the CQP Guarantors, (2) upon the liquidation or dissolution of a Guarantor, (3) following the release of a Guarantor from another guarantee that resulted in the creation of its guarantee of the CQP Senior Notes and (4) upon the legal defeasance or satisfaction and discharge of obligations under the indenture governing the CQP Senior Notes. In the event of a default in payment of the principal or interest by us, whether at maturity of the CQP Senior Notes or by declaration of acceleration, call for redemption or otherwise, legal proceedings may be instituted against the CQP Guarantors to enforce the guarantee.

The rights of holders of the CQP Senior Notes against the CQP Guarantors may be limited under the U.S. Bankruptcy Code or state fraudulent transfer or conveyance law. Each guarantee contains a provision intended to limit the Guarantor's liability to the maximum amount that it could incur without causing the incurrence of obligations under its guarantee to be a fraudulent conveyance or transfer under U.S. federal or state law. However, there can be no assurance as to what standard a court will apply in making a determination of the maximum liability of the CQP Guarantors. Moreover, this provision may not be effective to protect the guarantee from being voided under fraudulent conveyance laws. There is a possibility that the entire guarantee may be set aside, in which case the entire liability may be extinguished.

The following tables include summarized financial information of CQP (the **"Parent Issuer"**), and the CQP Guarantors (together with the Parent Issuer, the **"Obligor Group"**) on a combined basis. Investments in and equity in the earnings of SPL and, subject to certain conditions governing its guarantee, Sabine Pass LP (collectively with SPL, the **"Non-Guarantors"**), which are not currently members of the Obligor Group, have been excluded. Intercompany balances and transactions between entities in the Obligor Group have been eliminated. Although the creditors of the Obligor Group have no claim against the Non-Guarantors, the Obligor Group may gain access to the assets of the Non-Guarantors upon bankruptcy, liquidation or reorganization of the Non-Guarantors due to its investment in these entities. However, such claims to the assets of the Non-Guarantors would be subordinated to any claims by the Non-Guarantors' creditors, including trade creditors.

Summarized Balance Sheets (in millions)	**December 31,**	
	2023	**2022**
ASSETS		
Current assets		
Cash and cash equivalents	$ 575	$ 904
Accounts receivable from Non-Guarantors	55	55
Other current assets	39	40
Current assets—affiliate	86	171
Current assets with Non-Guarantors	1	—
Total current assets	756	1,170
Property, plant and equipment, net of accumulated depreciation	2,915	2,946
Other non-current assets, net	110	109
Total assets	$ 3,781	$ 4,225
LIABILITIES		
Current liabilities		
Due to affiliates	$ 121	$ 193
Deferred revenue from Non-Guarantors	3	24
Other current liabilities	177	95
Other current liabilities from Non-Guarantors	—	2
Total current liabilities	301	314
Long-term debt, net of premium, discount and debt issuance costs	5,542	4,159
Finance lease liabilities	14	18
Other non-current liabilities	67	78
Non-current liabilities—affiliate	18	18
Total liabilities	$ 5,942	$ 4,587

Summarized Statement of Income (in millions)	**Year Ended December 31, 2023**
Revenues	$ 199
Revenues from Non-Guarantors	549
Total revenues	748
Operating costs and expenses	247
Operating costs and expenses—affiliate	188
Operating costs and expenses—Non-Guarantors	12
Total operating costs and expenses	447
Income from operations	301
Net income	105

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)	$ 3.9	$ 14.1	$ 31.0	$ 49.0
LNG revenues (variable fees) (3)	5.1	24.4	60.1	89.6
Total	$ 9.0	$ 38.5	$ 91.1	$ 138.6

(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 (including $1.4 billion and $7.6 billion of fixed fees and variable fees, respectively, from affiliates) exclude revenues from contracts with original expected durations of one year or less. 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, including affiliate) reflect the assumption that customers elect to take delivery of all cargoes made available under the contract. LNG revenues (variable fees, including affiliate) 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 agreement, we have contracted approximately 85% of the total anticipated production from the Liquefaction Project, with approximately 14 years of weighted average remaining life as of December 31, 2023, excluding volumes that are contractually subject to additional liquefaction capacity beyond what is currently in construction or operation. The majority of the contracted capacity is comprised of fixed-price, long-term SPAs that SPL has executed with third parties to sell LNG from the Liquefaction Project. Under the SPAs, the customers purchase LNG on an FOB basis (delivered to the customer at the Sabine Pass LNG 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. In aggregate, the annual fixed fee portion to be paid by the third party SPA customers is approximately $3.4 billion. Our long-term SPA customers consist of creditworthy counterparties, with an average credit rating of A, A2 and A by S&P Global Ratings, 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.

In addition to the third party SPAs discussed above, SPL has executed agreements with Cheniere Marketing under SPAs and letter agreements at a price equal to 115% of Henry Hub plus a fixed fee, except for an SPA associated with an IPM agreement for which pricing is linked to international natural gas prices.

In August 2020, we entered into an arrangement with subsidiaries of Cheniere to provide the ability, in limited circumstances, to potentially fulfill commitments to LNG buyers in the event certain conditions impact operations at either the Sabine Pass or Corpus Christi liquefaction facilities. The purchase price for such cargoes would be (i) 115% of the applicable natural gas feedstock purchase price or (ii) a free-on-board U.S. Gulf Coast LNG market price, whichever is greater.

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 $1.7 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 in 2028.

Financially Disciplined Growth

Our significant land position at the Sabine Pass LNG Terminal provides potential development and investment opportunities for further liquefaction capacity expansion at a strategically advantaged location 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. The development of this 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 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)	$ 3.5	$ 10.0	$ 5.2	$ 18.7
Natural gas transportation and storage service agreements (4)	0.3	0.9	2.3	3.5
Other purchase obligations (5)	0.2	0.9	1.1	2.2
Leases (6)	—	0.1	0.1	0.2
Total	$ 4.0	$ 11.9	$ 8.7	$ 24.6

(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 our IPM agreements is based on global gas market prices less fixed liquefaction fees and certain costs incurred by us. Includes $0.8 billion under natural gas supply agreements with unsatisfied contractual conditions.

(4) Includes $0.2 billion of purchase obligations to related parties under the natural gas transportation and storage service agreements.

(5) Includes $1.2 billion of purchase obligations to affiliates under services agreements and payments under SPL's partial TUA assignment agreement with TotalEnergies Gas & Power North America, Inc. (**"TotalEnergies"**), as discussed in Note 13—Revenues of our Notes to Financial Statements.

(6) Includes payments under operating leases and finance leases. 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.

Natural Gas Supply, Transportation and Storage Service Agreements

We have secured natural gas feedstock for the Liquefaction Project through long-term natural gas supply agreements, including an IPM agreement. Under our IPM agreement, we pay for natural gas feedstock based on global gas market prices less fixed liquefaction fees and certain costs incurred by us. While our IPM agreement is not a revenue contract for accounting purposes, the payment structure for the purchase of natural gas under the IPM agreement 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 77% of the natural gas supply required to support the total forecasted production capacity of the Liquefaction Project 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 5,169 TBtu of natural gas feedstock through agreements with remaining fixed terms of up to approximately 14 years. A discussion of our natural gas supply and IPM agreements can be found in Note 8—Derivative Instruments of our Notes to Consolidated Financial Statements.

To ensure that we are able to transport natural gas feedstock to the Sabine Pass LNG Terminal, we have entered into firm pipeline transportation and other agreements to secure firm pipeline transportation capacity from third party 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 Project.

Capital Expenditures

Although we do not currently have any material capital expenditures under executed contracts, 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.

Leases

We have entered into leases for the use of tug vessels 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

Operational Services

We rely on our general partner to manage all aspects of the development, construction, operation and maintenance of the Sabine Pass LNG Terminal and to conduct our business. Because our general partner has no employees, it relies on subsidiaries of Cheniere to provide the personnel necessary to allow it to meet its management obligations to us, SPLNG, SPL and CTPL. As of December 31, 2023, Cheniere and its subsidiaries had 1,605 full-time employees, including 501 employees who directly supported the Sabine Pass LNG Terminal operations. See Note 14—Related Party Transactions of our Notes to Consolidated Financial Statements for a discussion of the services agreements pursuant to which general and administrative services are provided to us, SPLNG, SPL and CTPL.

Financially Disciplined Growth

Our significant land position at the Sabine Pass LNG Terminal provides 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 of our subsidiaries 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 Energy Inc. to provide the front end engineering and design work on the project. We expect that the SPL Expansion Project and any further expansion at 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	$ 6.7	$ 9.0	$ 16.0
Interest payments	0.9	2.2	1.2	4.3
Total	$ 1.2	$ 8.9	$ 10.2	$ 20.3

(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 $16.0 billion and credit facilities with no outstanding loan balances. As of December 31, 2023, we and SPL were 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 4.83%. Borrowings under our credit facilities are indexed to SOFR. Undrawn commitments under our credit facilities are subject to commitment fees ranging from 0.075% to 0.300%, 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 1.00% to 2.00%, subject to change based on the applicable entity's credit rating. We had $280 million aggregate amount of issued letters of credit under our credit facilities as of December 31, 2023.

Additional Future Cash Requirements for Financing

CQP Distribution

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash, which, as defined in our partnership agreement, consists of cash on hand at the end of a quarter less the amount of any reserves established by our general partner. All distributions paid to date have been made from accumulated operating surplus.

Capital Allocation Plan

In September 2022, the board of directors of Cheniere approved a revised long-term capital allocation plan, which may involve the repayment, redemption or repurchase, on the open market or otherwise, of debt, including senior notes of CQP and SPL.

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	$ 3,109	$ 4,149
Net cash used in investing activities	(227)	(451)
Net cash used in financing activities	(3,247)	(3,676)
Net increase (decrease) in cash, cash equivalents and restricted cash and cash equivalents	$ (365)	$ 22

Operating Cash Flows

The $1.0 billion decrease between the periods was primarily related to lower cash receipts from the sale of LNG cargoes from lower pricing per MMBtu, as a result of decreased Henry Hub pricing, and regasification fees. The decrease was partially offset by lower cash outflows for natural gas feedstock, mostly due to lower U.S. natural gas prices.

Investing Cash Flows

Cash outflows for property, plant and equipment during the year ended December 31, 2023 were primarily related to optimization and other site improvement projects. Cash outflows for property, plant and equipment during the year ended December 31, 2022 were primarily related to the construction costs for Train 6 of the Liquefaction Project, which achieved substantial completion on February 4, 2022.

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	$ 559
Redemptions and repayments of debt	(1,700)	(1,560)
Distributions	(2,907)	(2,635)
Other	(37)	(40)
Net cash used in financing activities	$ (3,247)	$ (3,676)

Debt Activity

During the year ended December 31, 2023, we 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, which leaves only $300 million to be repaid for debt maturing in 2024.

Cash Distributions to Unitholders

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement). Our available cash is our cash on hand at the end of a quarter less the amount of any reserves established by our general partner. All distributions paid to date have been made from accumulated operating surplus.

The following provides a summary of distributions paid by us during the years ended December 31, 2023 and 2022:

			Total Distribution (in millions)		
Date Paid	Period Covered by Distribution	Distribution Per Common Unit	Common Units	General Partner Units	Incentive Distribution Rights
November 14, 2023	July 1 - September 30, 2023	$ 1.030	$ 499	$ 14	$ 201
August 14, 2023	April 1 - June 30, 2023	1.030	499	14	201
May 15, 2023	January 1 - March 31, 2023	1.030	499	14	201
February 14, 2023	October 1 - December 31, 2022	1.070	518	15	220
November 14, 2022	July 1 - September 30, 2022	$ 1.070	$ 518	$ 15	$ 220
August 12, 2022	April 1 - June 30, 2022	1.060	513	15	215
May 13, 2022	January 1 - March 31, 2022	1.050	508	15	210
February 14, 2022	October 1 - December 31, 2021	0.700	339	8	47

In addition, Tug Services distributed $13 million and $12 million during the years ended December 31, 2023 and 2022, respectively, to Cheniere Terminals in accordance with their terminal marine service agreement, which is recognized as part of the distributions to the holder of our general partner interest.

On January 26, 2024, with respect to the fourth quarter of 2023, we declared a cash distribution of $1.035 per common unit to unitholders of record as of February 7, 2024 and the related general partner distribution that was paid on February 14, 2024. These distributions consist of a base amount of $0.775 per unit and a variable amount of $0.260 per unit.

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 3—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 3—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.

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	$ 1,318	$ (1,032)

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 agreement 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 $1.7 billion and $3.7 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 3—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

SPL has commodity derivatives consisting of natural gas supply contracts for the operation of the Liquefaction Project (the **"Liquefaction Supply Derivatives"**). In order to test the sensitivity of the fair value of the Liquefaction Supply Derivatives to changes in underlying commodity prices, management modeled a 10% change in the commodity price for natural gas for each delivery location 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	$ (1,657)	$ 362	$ (3,741)	$ 565

See Note 8—Derivative Instruments of our Notes to Consolidated Financial Statements for additional details about our derivative instruments.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

CHENIERE ENERGY PARTNERS, L.P.

MANAGEMENT'S REPORT TO THE UNITHOLDERS OF CHENIERE ENERGY PARTNERS, L.P.

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 Partners, L.P. (**"Cheniere Partners"**) and its subsidiaries. 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 Partners' 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 Partners 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 Partners' independent registered public accounting firm, KPMG LLP, has issued an audit report on Cheniere Partners' internal control over financial reporting as of December 31, 2023, which is contained in this Form 10-K.

Management's Certifications

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

Cheniere Energy Partners, L.P.

By: Cheniere Energy Partners GP, LLC,
Its general partner

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 Unitholders of Cheniere Energy Partners, L.P. and
Board of Directors of Cheniere Energy Partners GP, LLC
Cheniere Energy Partners, L.P.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Cheniere Energy Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2023 and 2022, the related consolidated statements of income, partners' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2023, and the related notes and financial statement schedule I (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership 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 Partnership'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 Partnership's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Partnership'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 Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the 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 3 and 8 to the consolidated financial statements, the Partnership recorded fair value of level 3 liquefaction supply derivatives of $(1,676) 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 Partnership's auditor since 2014.

Houston, Texas
February 21, 2024

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders of Cheniere Energy Partners, L.P. and
Board of Directors of Cheniere Energy Partners GP, LLC
Cheniere Energy Partners, L.P.:

Opinion on Internal Control Over Financial Reporting

We have audited Cheniere Energy Partners, L.P. and subsidiaries' (the Partnership) 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 Partnership 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 Partnership as of December 31, 2023 and 2022, the related consolidated statements of income, partners' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2023, and the related notes and financial statement schedule I (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 Partnership'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 Partnership'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 Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our 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 PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

(in millions, except per unit data)

	Year Ended December 31,		
	2023	**2022**	**2021**
Revenues			
LNG revenues	$ 6,991	$ 11,507	$ 7,639
LNG revenues—affiliate	2,475	4,568	1,472
LNG revenues—related party	—	—	1
Regasification revenues	135	1,068	269
Other revenues	63	63	53
Total revenues	9,664	17,206	9,434
Operating costs and expenses			
Cost of sales (excluding items shown separately below)	2,721	11,887	5,290
Cost of sales—affiliate	22	213	84
Cost of sales—related party	—	—	17
Operating and maintenance expense	879	757	635
Operating and maintenance expense—affiliate	166	166	142
Operating and maintenance expense—related party	62	72	46
General and administrative expense	10	5	9
General and administrative expense—affiliate	89	92	85
Depreciation and amortization expense	672	634	557
Other	6	—	11
Other—affiliate	1	—	1
Total operating costs and expenses	4,628	13,826	6,877
Income from operations	5,036	3,380	2,557
Other income (expense)			
Interest expense, net of capitalized interest	(823)	(870)	(831)
Loss on modification or extinguishment of debt	(6)	(33)	(101)
Interest and dividend income	46	21	1
Other income, net	1	—	2
Other income—affiliate	—	—	2
Total other expense	(782)	(882)	(927)
Net income	$ 4,254	$ 2,498	$ 1,630
Basic and diluted net income per common unit (1)	$ 6.95	$ 3.27	$ 3.00
Weighted average basic and diluted number of common units outstanding	484.0	484.0	484.0

(1) In computing basic and diluted net income per common unit, net income is reduced by the amount of undistributed net income allocated to participating securities other than common units, as required under the two-class method. See Note 15—Net Income per Common Unit.

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in millions, except unit data)

	December 31, 2023	December 31, 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
Trade receivables—affiliate	278	551
Advances to affiliate	84	177
Inventory	142	160
Current derivative assets	30	24
Margin deposits	—	35
Other current assets, net	43	50
Total current assets	1,581	2,620
Property, plant and equipment, net of accumulated depreciation	16,212	16,725
Operating lease assets	81	89
Debt issuance costs, net of accumulated amortization	16	8
Derivative assets	40	28
Other non-current assets, net	172	163
Total assets	$ 18,102	$ 19,633
LIABILITIES AND PARTNERS' DEFICIT		
Current liabilities		
Accounts payable	$ 69	$ 32
Accrued liabilities	806	1,378
Accrued liabilities—related party	5	6
Current debt, net of discount and debt issuance costs	300	—
Due to affiliates	55	74
Deferred revenue	114	144
Deferred revenue—affiliate	3	3
Current derivative liabilities	196	769
Other current liabilities	18	15
Total current liabilities	1,566	2,421
Long-term debt, net of discount and debt issuance costs	15,606	16,198
Operating lease liabilities	71	80
Finance lease liabilities	14	18
Derivative liabilities	1,531	3,024
Other non-current liabilities	75	—
Other non-current liabilities—affiliate	23	23
Commitments and contingencies (see Note 16)		
Partners' deficit		
Common unitholders' interest (484.0 million units issued and outstanding at both December 31, 2023 and 2022)	1,038	(1,118)
General partner's interest (2% interest with 9.9 million units issued and outstanding at both December 31, 2023 and 2022)	(1,822)	(1,013)
Total partners' deficit	(784)	(2,131)
Total liabilities and partners' deficit	$ 18,102	$ 19,633

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY (DEFICIT)
(in millions)

	Common Unitholders' Interest		General Partner's Interest		Total Partners' Equity (Deficit)
	Units	Amount	Units	Amount	
Balance at December 31, 2020	484.0	$ 714	9.9	$ (175)	$ 539
Net income	—	1,597	—	33	1,630
Distributions					
Common units, $2.66/unit	—	(1,287)	—	—	(1,287)
General partner units	—	—	—	(164)	(164)
Balance at December 31, 2021	484.0	1,024	9.9	(306)	718
Net income	—	2,448	—	50	2,498
Novated IPM Agreement (see Note 18)	—	(2,712)	—	—	(2,712)
Distributions					
Common units, $3.88/unit	—	(1,878)	—	—	(1,878)
General partner units	—	—	—	(757)	(757)
Balance at December 31, 2022	484.0	(1,118)	9.9	(1,013)	(2,131)
Net income	—	4,169	—	85	4,254
Distributions					
Common units, $4.16/unit	—	(2,013)	—	—	(2,013)
General partner units	—	—	—	(894)	(894)
Balance at December 31, 2023	484.0	$ 1,038	9.9	$ (1,822)	$ (784)

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2023	2022	2021
Cash flows from operating activities			
Net income	$ 4,254	$ 2,498	$ 1,630
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	672	634	557
Amortization of debt issuance costs, premium and discount	28	30	29
Loss on modification or extinguishment of debt	6	33	101
Total losses (gains) on derivative instruments, net	(2,082)	1,158	(29)
Total gains on derivatives instruments, net—related party	—	—	(2)
Net cash used for settlement of derivative instruments	(2)	(102)	(17)
Other	20	44	27
Changes in operating assets and liabilities:			
Trade and other receivables, net of current expected credit losses	254	(112)	(204)
Trade receivables—affiliate	273	(335)	(32)
Accounts receivable—related party	—	—	(1)
Advances to affiliate	85	(36)	2
Inventory	18	12	(68)
Margin deposits	35	(28)	(3)
Accounts payable and accrued liabilities	(467)	354	321
Accrued liabilities—related party	(2)	3	(1)
Due to affiliates	(18)	20	1
Total deferred revenue	46	(11)	18
Other, net	(11)	(24)	(38)
Other, net—affiliate	—	11	—
Net cash provided by operating activities	3,109	4,149	2,291
Cash flows from investing activities			
Property, plant and equipment, net	(220)	(451)	(648)
Other	(7)	—	—
Net cash used in investing activities	(227)	(451)	(648)
Cash flows from financing activities			
Proceeds from issuances of debt	1,397	559	3,182
Redemptions and repayments of debt	(1,700)	(1,560)	(3,600)
Distributions	(2,907)	(2,635)	(1,451)
Other	(37)	(40)	(107)
Net cash used in financing activities	(3,247)	(3,676)	(1,976)
Net increase (decrease) in cash, cash equivalents and restricted cash and cash equivalents	(365)	22	(333)
Cash, cash equivalents and restricted cash and cash equivalents—beginning of period	996	974	1,307
Cash, cash equivalents and restricted cash and cash equivalents—end of period	$ 631	$ 996	$ 974

Balances per Consolidated Balance Sheets:

	December 31,	
	2023	2022
Cash and cash equivalents	$ 575	$ 904
Restricted cash and cash equivalents	56	92
Total cash, cash equivalents and restricted cash and cash equivalents	$ 631	$ 996

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

NOTE 1—ORGANIZATION AND NATURE OF OPERATIONS

We own the natural gas liquefaction and export facility located in Cameron Parish, Louisiana at Sabine Pass (the **"Sabine Pass LNG Terminal"**) which has six operational Trains, for a total production capacity of approximately 30 mtpa of LNG (the **"Liquefaction Project"**). The Sabine Pass LNG Terminal also has operational regasification facilities that include five LNG storage tanks, vaporizers and three marine berths. Additionally, the Sabine Pass LNG Terminal includes a 94-mile natural gas supply pipeline owned by our subsidiary, CTPL, that interconnects the Sabine Pass LNG Terminal with several large interstate and intrastate pipelines (the **"Creole Trail Pipeline"**).

We are pursuing a certain expansion project to provide additional liquefaction capacity, and we have commenced commercialization to support the additional liquefaction capacity associated with this expansion project.

We do not have employees and thus we and our subsidiaries have various services agreements with affiliates of Cheniere in the ordinary course of business, including services required to construct, operate and maintain the Liquefaction Project, and administrative services. See Note 14—Related Party Transactions for additional details of the activity under these services agreements during the years ended December 31, 2023, 2022 and 2021.

We are not subject to federal or state income taxes, as our partners are taxed individually on their allocable share of our taxable income. At December 31, 2023, the tax basis of our assets and liabilities was $9.9 billion less than the reported amounts of our assets and liabilities. See Note 14—Related Party Transactions for details about income taxes under our tax sharing agreements.

As of December 31, 2023, Cheniere owned 48.6% of our limited partner interest in the form of 239.9 million of our common units. Cheniere also owns 100% of our general partner interest and our incentive distribution rights (**"IDRs"**).

NOTE 2—UNITHOLDERS' EQUITY

The common units represent limited partner interests in us, which entitle the unitholders to participate in partnership distributions and exercise the rights and privileges available to limited partners under our partnership agreement. Although common unitholders are not obligated to fund losses of the Partnership, their capital account, which would be considered in allocating the net assets of the Partnership were it to be liquidated, continues to share in losses.

The general partner interest is entitled to at least 2% of all distributions made by us. In addition, the general partner holds IDRs, which allow the general partner to receive a higher percentage of quarterly distributions of available cash from operating surplus as additional target levels are met, but may transfer these rights separately from its general partner interest. The higher percentages range from 15% to 50%, inclusive of the general partner interest.

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash, which, as defined in our partnership agreement, is generally our cash is our cash on hand at the end of a quarter less the amount of any reserves established by our general partner. All distributions we have paid to date have been made from accumulated operating surplus as defined in the partnership agreement.

As of December 31, 2023, our total securities beneficially owned in the form of common units were held 48.6% by Cheniere, 41.5% by CQP Target Holdco L.L.C. (**"CQP Target Holdco"**) and other affiliates of Blackstone Inc. (**"Blackstone"**) and Brookfield Asset Management Inc. (**"Brookfield"**) and 7.9% by the public. All of our 2% general partner interest was held by Cheniere. CQP Target Holdco's equity interests are 50.0% owned by BIP Chinook Holdco L.L.C., an affiliate of Blackstone, and 50.0% owned by BIF IV Cypress Aggregator (Delaware) LLC, an affiliate of Brookfield. The ownership of CQP Target Holdco, Blackstone and Brookfield are based on their most recent filings with the SEC.

NOTE 3—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 CQP and its majority owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation.

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 and asset retirement obligations **("AROs")**, 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 8—Derivative Instruments.

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.

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 terminal 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 terminal.

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. Refer to Note 7—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 Income 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 30 years as of both December 31, 2023 and 2022.

Interest Capitalization

We capitalize interest costs mainly during the construction period of our LNG terminal 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 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 8—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.

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.

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.

As of December 31, 2023, SPL had SPAs with initial terms of 10 or more years with a total of 11 different third party customers and had agreements with Cheniere Marketing. SPL is dependent on the respective customers' creditworthiness and their willingness to perform under their respective SPAs.

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

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) 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 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 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.

NOTE 4—RESTRICTED CASH AND CASH EQUIVALENTS

As of December 31, 2023 and 2022, we had \$56 million and \$92 million of restricted cash and cash equivalents, respectively, for which the usage or withdrawal of such cash is contractually or legally restricted to the payment of liabilities related to the Liquefaction Project as required under certain debt arrangements.

NOTE 5—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	$ 364	$ 603
Other receivables	9	24
Total trade and other receivables, net of current expected credit losses	$ 373	$ 627

NOTE 6—INVENTORY

Inventory consisted of the following (in millions):

	December 31, 2023	December 31, 2022
Materials	$ 107	$ 103
LNG	12	27
Natural gas	22	28
Other	1	2
Total inventory	$ 142	$ 160

NOTE 7—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
LNG terminal		
Terminal and interconnecting pipeline facilities	$ 20,176	$ 20,072
Construction-in-process	189	140
Accumulated depreciation	(4,173)	(3,512)
Total LNG terminal, net of accumulated depreciation	16,192	16,700
Fixed assets		
Fixed assets	29	29
Accumulated depreciation	(26)	(25)
Total fixed assets, net of accumulated depreciation	3	4
Assets under finance leases		
Tug vessels	23	23
Accumulated depreciation	(6)	(2)
Total assets under finance leases, net of accumulated depreciation	17	21
Property, plant and equipment, net of accumulated depreciation	$ 16,212	$ 16,725

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

	Year Ended December 31, 2023	2022	2021
Depreciation expense	$ 667	$ 630	$ 552
Offsets to LNG terminal costs (1)	—	148	105

(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 Project during the testing phase for its construction.

LNG Terminal Costs

The Sabine Pass LNG Terminal is depreciated using the straight-line depreciation method applied to groups of LNG terminal assets with varying useful lives. The identifiable components of the Sabine Pass LNG Terminal 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

Our fixed assets 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 consists of certain tug vessels 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 8—DERIVATIVE INSTRUMENTS

We have commodity derivatives consisting of natural gas supply contracts, including those under our IPM agreements, for the operation of the Liquefaction Project and expansion project, as well as the associated economic hedges (collectively, the **"Liquefaction Supply Derivatives"**).

We recognize our derivative instruments as either assets or liabilities and measure those instruments at fair value. None of SPL's 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 Income 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)	$ 18	$ 1	$ (1,676)	$ (1,657)	$ (12)	$ (10)	$ (3,719)	$ (3,741)

We value the Liquefaction Supply 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 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. 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 the natural gas positions within the 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 the 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	$(1,676)	Market approach incorporating present value techniques	Henry Hub basis spread	$(0.483) - $0.423 / $0.014
		Option pricing model	International LNG pricing spread, relative to Henry Hub (2)	113% - 379% / 194%

(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 the Liquefaction Supply Derivatives.

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

	Year Ended December 31, 2023	2022	2021
Balance, beginning of period	$ (3,719)	$ 38	$ (21)
Realized and change in fair value gains (losses) included in net income (1):			
Included in cost of sales, existing deals (2)	1,302	(228)	74
Included in cost of sales, new deals (3)	16	(804)	—
Purchases and settlements:			
Purchases (4)	—	(2,712)	(10)
Settlements (5)	724	(13)	(5)
Transfers out of level 3 (6)	1	—	—
Balance, end of period	$ (1,676)	$ (3,719)	$ 38
Favorable (unfavorable) changes in fair value relating to instruments still held at the end of the period	$ 1,318	$ (1,032)	$ 74

(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. For further discussion of the IPM agreement that was novated to us in 2022, see Note 18—Supplemental Cash Flow Information.

(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 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 SPL to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments, in instances when the derivative instruments are in an asset position. Additionally, counterparties are at risk that SPL will be unable to meet its commitments in instances where the derivative instruments are in a liability position. We incorporate both SPL's 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 the 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.

Liquefaction Supply Derivatives

SPL holds 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.

The forward notional amount for the Liquefaction Supply Derivatives was approximately 6,245 TBtu and 5,972 TBtu as of December 31, 2023 and 2022, respectively, 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 the Liquefaction Supply Derivatives recorded on our Consolidated Statements of Income (in millions):

	Gain (Loss) Recognized in Consolidated Statements of Income		
	Year Ended December 31,		
Consolidated Statements of Income Location (1)	**2023**	**2022**	**2021**
LNG revenues	$ —	$ 1	$ (1)
Cost of sales	2,082	(1,159)	30
Cost of sales—related party	—	—	2

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

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

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

	Fair Value Measurements as of (1)	
Consolidated Balance Sheets Location	December 31, 2023	December 31, 2022
Current derivative assets	$ 30	$ 24
Derivative assets	40	28
Total derivative assets	70	52
Current derivative liabilities	(196)	(769)
Derivative liabilities	(1,531)	(3,024)
Total derivative liabilities	(1,727)	(3,793)
Derivative liability, net	$ (1,657)	$ (3,741)

(1) Does not include collateral posted by counterparties to us of $4 million as of December 31, 2023, which is included in other current liabilities on our Consolidated Balance Sheets, and collateral posted with counterparties by us of $35 million as of December 31, 2022, which is included in margin deposits on our Consolidated Balance Sheets.

Consolidated Balance Sheets Presentation

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

	Liquefaction Supply Derivatives	
	December 31, 2023	December 31, 2022
Gross assets	$ 88	$ 57
Offsetting amounts	(18)	(5)
Net assets	$ 70	$ 52
Gross liabilities	$ (1,746)	$ (3,814)
Offsetting amounts	19	21
Net liabilities	$ (1,727)	$ (3,793)

NOTE 9—OTHER NON-CURRENT ASSETS, NET

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

	December 31,	
	2023	2022
Advances of cash and conveyed assets to service providers for infrastructure to support LNG terminal, net of accumulated amortization	$ 120	$ 109
Tax-related prepayments and receivables	17	17
Other, net	35	37
Total other non-current assets, net	$ 172	$ 163

NOTE 10—ACCRUED LIABILITIES

Accrued liabilities consisted of the following (in millions):

	December 31, 2023	December 31, 2022
Natural gas purchases	$ 464	$ 1,017
Interest costs and related debt fees	256	218
LNG terminal and related pipeline costs	77	137
Other accrued liabilities	9	6
Total accrued liabilities	$ 806	$ 1,378

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
Total debt	16,032	16,332
Current debt, net of discount and debt issuance costs	(300)	—
Long-term portion of unamortized discount and debt issuance costs, net	(126)	(134)
Total long-term debt, net of discount and debt issuance costs	$ 15,606	$ 16,198

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 our 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 our 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 our senior obligations, ranking equally in right of payment with our other existing and future unsubordinated debt and senior to any of its future subordinated debt. In the event that the aggregate amount of our 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 of our existing and future tangible and intangible assets and rights 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. We 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.

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	2,052
2026	1,607
2027	1,612
2028	1,468
Thereafter	8,993
Total	$ 16,032

Credit Facilities

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

	SPL Revolving Credit Facility (1) (2)	CQP Revolving Credit Facility (1)(3)
Total facility size	$ 1,000	$ 1,000
Less:		
Outstanding balance	—	—
Letters of credit issued	280	—
Available commitment	$ 720	$ 1,000
Priority ranking	Senior secured	Senior unsecured
Interest rate on available balance (4)	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%
Commitment fees on undrawn balance (4)	0.075% - 0.30%	0.10% - 0.30%
Maturity date	June 23, 2028	June 23, 2028

(1) In June 2023, we 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 margin on the interest rate and the commitment fees is subject to change based on the applicable entity's credit rating.

Loss on Extinguishment of Debt Related to Termination 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—Revenues 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 and our restricted subsidiaries' ability to make certain investments or pay dividends or distributions. SPL is restricted from making distributions under agreements governing its 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 $56 million.

As of December 31, 2023, we and SPL were in compliance with all covenants related to our 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
Total interest cost	$ 831	$ 910	$ 963
Capitalized interest	(8)	(40)	(132)
Total interest expense, net of capitalized interest	$ 823	$ 870	$ 831

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	$ 16,032	$ 15,636	$ 16,332	$ 15,386

(1) As of both December 31, 2023 and 2022, $1.3 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 tug vessels and land sites. All of our leases are classified as operating leases except for certain of our tug vessels, 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):

	Consolidated Balance Sheets Location	December 31, 2023	December 31, 2022
Right-of-use assets—Operating	Operating lease assets	$ 81	$ 89
Right-of-use assets—Financing	Property, plant and equipment, net of accumulated depreciation	17	21
Total right-of-use assets		$ 98	$ 110
Current operating lease liabilities	Other current liabilities	10	10
Current finance lease liabilities	Other current liabilities	4	4
Non-current operating lease liabilities	Operating lease liabilities	71	80
Non-current finance lease liabilities	Finance lease liabilities	14	18
Total lease liabilities		$ 99	112

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

	Consolidated Statements of Income Location	Year Ended December 31, 2023	2022	2021
Operating lease cost (1)	Operating costs and expenses (2)	$ 13	$ 13	$ 12
Finance lease cost:				
Amortization of right-of-use assets	Depreciation and amortization expense	4	2	—
Interest on lease liabilities	Interest expense, net of capitalized interest	1	—	—
Total lease cost		$ 18	$ 15	$ 12

(1) Includes $1 million of variable lease costs incurred during each of the years ended December 31, 2023, 2022 and 2021, respectively.

(2) Presented in cost of sales, operating and maintenance expense, general and administrative expense or general and administrative expense—affiliate 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	$ 12	$ 5
2025	12	5
2026	12	5
2027	12	5
2028	3	—
Thereafter	92	—
Total lease payments	143	20
Less: Interest	(62)	(2)
Present value of lease liabilities	$ 81	$ 18

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)	24.6	4.1	23.8	5.1
Weighted-average discount rate	3.9 %	4.8 %	3.8 %	4.8 %

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	12	10	11
Right-of-use assets obtained in exchange for operating lease liabilities	1	—	7
Right-of-use assets obtained in exchange for finance lease liabilities	—	23	—

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	$ 6,991	$ 11,506	$ 7,640
LNG revenues—affiliate	2,475	4,568	1,472
LNG revenues—related party	—	—	1
Regasification revenues	135	1,068	269
Other revenues	63	63	53
Total revenues from contracts with customers	9,664	17,205	9,435
Net derivative gain (loss) (1)	—	1	(1)
Total revenues	$ 9,664	$ 17,206	$ 9,434

(1) See Note 8—Derivative Instruments for additional information about our derivatives.

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). 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. Additionally, we have agreements with Cheniere Marketing for which the related revenues are recorded as LNG revenues—affiliate. See Note 14—Related Party Transactions for additional information regarding these agreements.

Revenues from the sale of LNG are recognized at a point in time when the LNG is delivered to the customer, at the Sabine Pass LNG Terminal, 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.

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 Income, and where we have concluded that we acted as an agent are netted within cost of sales in our Consolidated Statements of Income.

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 Liquefaction 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. Cost 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 Income, and an offsetting $31 million reported, upon receipt of the Termination Fee, as a loss on extinguishment of debt on our Consolidated Statements of Income 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	$ 1	$ 1

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.

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	$ 144
Cash received but not yet recognized in revenue	190
Revenue recognized from prior period deferral	(144)
Deferred revenue, end of period	$ 190

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

	Year Ended December 31, 2023
Deferred revenue—affiliate, beginning of period	$ 8
Cash received but not yet recognized in revenue	5
Revenue recognized from prior period deferral	(8)
Deferred revenue—affiliate, end of period	$ 5

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)	$ 47.6	8	$ 50.8	8
LNG revenues—affiliate	1.4	2	2.0	2
Regasification revenues	0.7	3	0.8	4
Total revenues	$ 49.7		$ 53.6	

(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	56 %	74 %
LNG revenues—affiliate	69 %	75 %
Regasification revenues	7 %	2 %

NOTE 14—RELATED PARTY TRANSACTIONS

Below is a summary of our transactions with our affiliates and other related parties, all in the ordinary course of business, as reported on our Consolidated Statements of Income (in millions):

	Year Ended December 31,		
	2023	2022	2021
LNG revenues—affiliate			
SPAs and Letter Agreements with Cheniere Marketing (1)	$ 2,472	$ 4,565	$ 1,453
Contracts for Sale and Purchase of Natural Gas and LNG with other affiliates (2)	3	3	19
Total LNG revenues—affiliate	2,475	4,568	1,472
LNG revenues—related party			
Natural Gas Transportation and Storage Agreements (3)	—	—	1
Cost of sales—affiliate			
Cheniere Marketing Agreements (1)	—	—	34
Contracts for Sale and Purchase of Natural Gas and LNG (2)	22	213	50
Total cost of sales—affiliate	22	213	84
Cost of sales—related party			
Natural Gas Transportation and Storage Agreements (3)	—	—	1
Natural Gas Supply Agreements (4)	—	—	16
Total cost of sales—related party	—	—	17
Operating and maintenance expense—affiliate			
Services Agreements (5)	166	166	142
Operating and maintenance expense—related party			
Natural Gas Transportation and Storage Agreements (3)	62	72	46
General and administrative expense—affiliate			
Services Agreements (5)	89	92	85
Other—affiliate			
Services Agreements (5)	1	—	1
Other income—affiliate			
Cooperative Endeavor Agreement (6)	—	—	2

(1) SPL primarily sells LNG to Cheniere Marketing under SPAs and letter agreements at a price equal to 115% of Henry Hub plus a fixed fee, except for an SPA associated with an IPM agreement for which pricing is linked to international natural gas prices. SPL also has a master SPA agreement with Cheniere Marketing that allows us to sell and purchase LNG with Cheniere Marketing by executing and delivering confirmations under this agreement. As of December 31, 2023 and 2022, SPL had $272 million and $551 million of trade receivables—affiliate, respectively, under these agreements with Cheniere Marketing. In addition, SPL has an arrangement with subsidiaries of Cheniere to provide the ability, in limited circumstances, to potentially fulfill commitments to LNG buyers in the event operational conditions impact operations at either the Sabine Pass or Corpus Christi liquefaction facilities. The purchase price for such cargoes would be the greater of: (a) 115% of the applicable natural gas feedstock purchase price or (b) an FOB U.S. Gulf Coast LNG market price.

(2) SPL has an agreement with Corpus Christi Liquefaction, LLC (**"CCL"**) that allows them to sell and purchase natural gas and LNG from each other. Natural gas purchased under these agreements is initially recorded as inventory and then to cost of sales—affiliate upon its sale, except for purchases related to commissioning activities which are capitalized as LNG terminal construction-in-process. Additionally, SPLNG is able to sell and purchase natural gas and LNG under agreements with Cheniere Marketing. As of December 31, 2023 and 2022, we had $4 million and zero of trade receivables—affiliate, respectively, under these agreements.

(3) SPL is party to various natural gas transportation and storage agreements and CTPL is party to an operational balancing agreement with a related party in the ordinary course of business for the operation of the Liquefaction Project. This related party is partially owned by Brookfield, who indirectly owns a portion of our limited partner interests. SPL recorded accrued liabilities—related party of $5 million and $6 million as of December 31, 2023 and 2022, respectively, with this related party.

(4) We were a party to a natural gas supply agreement with a related party in the ordinary course of business, to obtain a fixed minimum daily volume of feed gas for the operation of the Liquefaction Project. This related party was partially owned by Blackstone, who also partially owns CQP's limited partner interests. However, this entity was acquired by a non-related party on December 31, 2021; therefore, as of such date, this agreement ceased to be considered a related party agreement.

(5) We do not have employees and thus we and our subsidiaries have various services agreements with affiliates of Cheniere in the ordinary course of business, including services required to construct, operate and maintain the Liquefaction Project, and administrative services. Prior to the substantial completion of each Train of the Liquefaction Project, our payments under the services agreements were primarily based on a cost reimbursement structure, and following the completion of each Train, our payments include a fixed monthly fee (indexed for inflation) per mtpa in addition to the reimbursement of costs. As of December 31, 2023 and 2022, we had $84 million and $177 million of advances to affiliates, respectively, under the services agreements. The non-reimbursement amounts incurred under these agreements are recorded in general and administrative expense—affiliate.

(6) SPLNG executed Cooperative Endeavor Agreements (**"CEAs"**) with various Cameron Parish, Louisiana taxing authorities that allowed them to collect certain advanced payments of annual ad valorem taxes from SPLNG from 2007 through 2016. This initiative represented an aggregate commitment of $25 million over 10 years in order to aid in their reconstruction efforts following Hurricane Rita. In exchange for SPLNG's advance payments of annual ad valorem taxes, Cameron Parish granted SPLNG a dollar-for-dollar credit against future ad valorem taxes to be levied against the Sabine Pass LNG Terminal as early as 2019. In 2018, SPLNG entered into a Memorandum of Understanding, which forgave approximately $7.5 million of the dollar-for-dollar credits, and in 2022, an agreement was reached to defer the commencement of the dollar-for-dollar credits until 2027. As of both December 31, 2023 and 2022, we had $17 million of amounts associated with dollar-for-dollar credits due on advance tax payments to the taxing authorities recorded to other non-current assets on our Consolidated Balance Sheets. Beginning in September 2007, SPLNG entered into various agreements with Cheniere Marketing, pursuant to which Cheniere Marketing would pay SPLNG additional TUA revenues equal to any and all amounts payable by SPLNG to the Cameron Parish taxing authorities under the CEAs. In exchange for such amounts received as TUA revenues from Cheniere Marketing, SPLNG will make payments to Cheniere Marketing equal to the dollar-for-dollar credit applied to the ad valorem tax levied against the Sabine Pass LNG Terminal. We had $17 million of other non-current liabilities—affiliate as of both December 31, 2023 and 2022 from these payments received from Cheniere Marketing.

We had $55 million and $74 million due to affiliates as of December 31, 2023 and 2022, respectively, under agreements with affiliates as described above.

Disclosure of future consideration under revenue contracts with affiliates is included in Note 13—Revenues. Additionally, disclosure of future contractual obligations with affiliates and related parties is included in Note 16—Commitments and Contingencies.

Other Agreements

Terminal Marine Services Agreement

In connection with its tug boat leases, Tug Services entered into an agreement with Cheniere Terminals to provide its LNG cargo vessels with tug boat and marine services at the Sabine Pass LNG Terminal. The agreement also provides that Tug Services shall contingently pay Cheniere Terminals a portion of its future revenues. Under this agreement, Tug Services distributed $13 million, $12 million and $9 million during the years ended December 31, 2023, 2022 and 2021, respectively, to Cheniere Terminals, which is recognized as part of the distributions to our general partner interest holders on our Consolidated Statements of Partners' Equity (Deficit).

State Tax Sharing Agreements

SPLNG, SPL and CTPL each have a state tax sharing agreement with Cheniere. Under these agreements, Cheniere has agreed to prepare and file all state and local tax returns which each of the entities and Cheniere are required to file on a combined basis and to timely pay the combined state and local tax liability. If Cheniere, in its sole discretion, demands payment, each of the respective entities will pay to Cheniere an amount equal to the state and local tax that each of the entities would be required to pay if its state and local tax liability were calculated on a separate company basis. To date, there have been no state and local tax payments demanded by Cheniere under the tax sharing agreements. The agreements for SPLNG, SPL and CTPL are effective for tax returns due on or after January 2008, August 2012 and May 2013, respectively.

NOTE 15—NET INCOME PER COMMON UNIT

Net income per common unit for a given period is based on the distributions we incur to the common unitholders with respect to earnings or losses of the reporting period plus an allocation of undistributed net income (loss) based on provisions of the partnership agreement, divided by the weighted average number of common units outstanding. Distributions declared by us during the period are presented on the Consolidated Statements of Partners' Equity (Deficit). On January 26, 2024, we declared a cash distribution of $1.035 per common unit to unitholders of record as of February 7, 2024 and the related general partner distribution that was paid on February 14, 2024 with respect to the three months ended December 31, 2023. These distributions consist of a base amount of $0.775 per unit and a variable amount of $0.260 per unit.

The two-class method dictates that net income for a period be reduced by the amount of available cash that will be distributed with respect to that period and that any residual amount representing undistributed net income be allocated to common unitholders and other participating unitholders to the extent that each unit may share in net income as if all of the net income for the period had been distributed in accordance with the partnership agreement. Undistributed income is allocated to participating securities based on the distribution waterfall for available cash specified in the partnership agreement. Undistributed losses (including those resulting from distributions in excess of net income) are allocated to common units and other participating securities on a pro rata basis based on provisions of the partnership agreement. Distributions are treated as distributed earnings in the computation of earnings per common unit even though cash distributions are not necessarily derived from current or prior period earnings.

The following table provides a reconciliation of net income and the allocation of net income to the common units, the subordinated units, the general partner units and IDRs for purposes of computing basic and diluted net income per unit (in millions, except per unit data).

	Total	Limited Partner Common Units	General Partner Units	IDR
Year Ended December 31, 2023				
Net income	$ 4,254			
Declared distributions	2,861	1,997	57	807
Assumed allocation of undistributed net income (1)	$ 1,393	1,366	28	—
Assumed allocation of net income		$ 3,363	$ 85	$ 807
Weighted average units outstanding		484.0		
Basic and diluted net income per unit		$ 6.95		
Year Ended December 31, 2022				
Net income	$ 2,498			
Declared distributions	2,982	2,057	60	865
Assumed allocation of undistributed net loss (1)	$ (484)	(474)	(10)	—
Assumed allocation of net income		$ 1,583	$ 50	$ 865
Weighted average units outstanding		484.0		
Basic and diluted net income per unit		$ 3.27		
Year Ended December 31, 2021				
Net income	$ 1,630			
Declared distributions	1,486	1,309	30	147
Assumed allocation of undistributed net income (1)	$ 144	141	3	—
Assumed allocation of net income		$ 1,450	$ 33	$ 147
Weighted average units outstanding		484.0		
Basic and diluted net income per unit (2)		$ 3.00		

(1) Under our partnership agreement, the IDRs participate in net income only to the extent of the amount of cash distributions actually declared, thereby excluding the IDRs from participating in undistributed net income (loss).

(2) Basic and diluted net income per unit in the table may not recalculate exactly due to rounding because it is calculated based on whole numbers, not the rounded numbers presented.

NOTE 16—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.

Natural Gas Supply, Transportation and Storage Service Agreements

SPL has a physical natural gas supply contracts to secure natural gas feedstock for the Liquefaction Project. 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 has natural gas transportation and storage service agreements for the Liquefaction Project. 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 terms of SPL's natural gas storage service agreements range up to 10 years.

As of December 31, 2023, SPL's obligations 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)
2024	$ 3.7	$ 0.1
2025	3.5	0.1
2026	2.8	—
2027	2.4	—
2028	2.1	—
Thereafter	7.5	—
Total	$ 22.0	$ 0.2

(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.

Services and Other Agreements

We have certain fixed commitments under services and other agreements of $1.0 billion with third parties and $1.2 billion with affiliates. See Note 14—Related Party Transactions for additional information regarding such agreements with affiliates.

Environmental and Regulatory Matters

The Sabine Pass LNG Terminal and CTPL 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 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. In the opinion of management, as of December 31, 2023, there were no pending legal matters that would reasonably be expected to have a material impact on our operating results, financial position or cash flows.

NOTE 17—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	23%	22%	24%	22%	27%
Customer B	16%	15%	17%	16%	*
Customer C	16%	15%	17%	12%	18%
Customer D	15%	15%	16%	15%	18%
Customer E	11%	10%	11%	12%	*
Customer F	*	*	*	—%	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. Substantially all of our long-lived assets are located in the United States.

	Revenues from External Customers		
	Year Ended December 31,		
	2023	2022	2021
United States	$ 2,601	$ 5,278	$ 2,872
South Korea	1,169	1,932	1,336
India	1,119	1,951	1,342
Ireland	1,058	1,858	1,237
United Kingdom	717	1,026	966
Switzerland	245	593	208
Other countries	280	—	—
Total	$ 7,189	$ 12,638	$ 7,961

NOTE 18—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	$ 748	$ 777	$ 812
Non-cash investing activity:			
Unpaid purchases of property, plant and equipment, net and other non-current assets, net	32	103	76

Novation of IPM Agreement from Corpus Christi Liquefaction Stage III, LLC **("CCL Stage III")**

In March 2022, in connection with a prior commitment from Cheniere to collateralize financing for Train 6 of the Liquefaction Project, SPL and CCL Stage III, formerly a wholly owned direct subsidiary of Cheniere that merged with and into CCL, entered into an agreement to assign to SPL an IPM agreement to purchase 140,000 MMBtu per day of natural gas at a price based on the Platts Japan Korea Marker (**"JKM"**), for a term of approximately 15 years beginning in early 2023. The transaction was accounted for as a transfer between entities under common control, which required us to recognize the obligations assumed at the historical basis of Cheniere. Upon the transfer, which occurred on March 15, 2022, we recognized $2.7 billion in distributions to Cheniere's common unitholder interest within our Consolidated Statements of Partners' Equity (Deficit) based on our assumption of current derivative liabilities and derivative liabilities of $142 million and $2.6 billion, respectively, which represented a non-cash financing activity.

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 general partner's 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 general partner's 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 the directors and executive officers of our general partner to enter into trading plans designed to comply with Rule 10b5-1. During the three-month period ending December 31, 2023, none of the executive officers or directors of our general partner 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

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS OF OUR GENERAL PARTNER AND CORPORATE GOVERNANCE

Management of Cheniere Partners

Cheniere Partners GP, as our general partner, manages our operations and activities. Our general partner is not elected by our unitholders and is not subject to re-election on a regular basis in the future. The directors of our general partner are elected by the sole member of the general partner. Unitholders are not entitled to elect the directors of our general partner or to participate directly or indirectly in our management or operations.

Audit Committee

The board of directors of our general partner has appointed an audit committee composed of Lon McCain, chairman, Vincent Pagano, Jr. and Oliver G. Richard, III, each of whom is an independent director and satisfies the additional independence and financial literacy requirements for audit committee members provided for in the listing standards of the NYSE and the Exchange Act. In addition, the board of directors of our general partner has determined that Lon McCain and Oliver G. Richard, III meet the qualifications of an audit committee financial expert as such term is defined by the SEC.

The audit committee assists the board of directors of our general partner in its oversight of the integrity of our Consolidated Financial Statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all audit services and related fees and the terms thereof and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the audit committee. Our audit committee charter is posted at *https://cqpir.cheniere.com/company-information/governance-documents.*

Conflicts Committee

Under our partnership agreement, the board of directors of our general partner has appointed a conflicts committee composed of the independent directors, Vincent Pagano, Jr., chairman, James R. Ball, Lon McCain and Oliver G. Richard, III, to review specific matters that the board believes may involve conflicts of interest. The conflicts committee will determine if the resolution of a conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be security holders, officers or employees of our general partner, directors, officers, or employees of affiliates of the general partner or holders of any ownership interest in us other than common units or other publicly traded units and must meet the independence standards established by the NYSE, the Exchange Act and other federal securities laws. Any matter approved by the conflicts committee is conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties that it may owe us or our unitholders.

CMI SPA Committee

The board of directors of our general partner has formed a CMI SPA Committee, composed of James Ball, chairman, Taylor Johnson and Scott Peak to approve LNG sales entered into between Cheniere Marketing and SPL.

Other

We do not have a nominating committee because the directors of our general partner manage our operations.

We also do not have a compensation committee. We have no employees, directors or officers. We are managed by our general partner, Cheniere Partners GP. Our general partner has paid no cash compensation to its executive officers since its inception. All of the executive officers of our general partner are also executive officers of Cheniere. Cheniere compensates these officers for the performance of their duties as executive officers of Cheniere, which includes managing our partnership. Cheniere does not allocate this compensation between services for us and services for Cheniere and its affiliates.

Directors and Executive Officers of Our General Partner

The following sets forth information, as of February 16, 2024, regarding the individuals who currently serve on the board of directors and as executive officers of our general partner. The appointments of Messrs. Baker, Dell'Amore, and Peak to the board of directors of our general partner were made pursuant to the rights of CQP Holdco LP (f/k/a Blackstone CQP Holdco) (**"CQP Holdco"**) under the Third Amended and Restated Limited Liability Company Agreement of our general partner (the **"GP LLC Agreement"**) to appoint certain directors to the board of directors of our general partner.

Name	Age	Election Date	Position with Our General Partner
Jack A. Fusco	61	May 2016	Chairman of the Board and President and Chief Executive Officer
Brian Baker	53	April 2023	Director
James R. Ball	73	September 2012	Director
Zach Davis	39	August 2020	Director and Executive Vice President and Chief Financial Officer
Christopher Dell'Amore	34	January 2023	Director
Corey Grindal	52	September 2022	Director and Executive Vice President and Chief Operating Officer
Taylor Johnson	44	June 2023	Director and Deputy General Counsel
Lon McCain	76	March 2007	Director
Vincent Pagano, Jr.	73	December 2012	Director
Scott Peak	43	April 2023	Director
Oliver G. Richard, III	71	September 2012	Director

Jack A. Fusco

Chairman of the Board and President and Chief Executive Officer of our general partner

Mr. Fusco has served as President and Chief Executive Officer of Cheniere since May 2016 and as a director since June 2016. In addition, Mr. Fusco serves as Chairman, President and Chief Executive Officer of our general partner. Mr. Fusco is also a Manager, President and Chief Executive Officer of the general partner of Sabine Pass LNG, L.P. and Chief Executive Officer of Sabine Pass Liquefaction, LLC. Mr. Fusco received recognition as Best CEO in the electric industry by Institutional Investor in 2012 as ranked by all industry analysts and for Best Investor Relations by a CEO or Chairman among all mid-cap companies by IR Magazine in 2013. Institutional Investor also recognized Mr. Fusco as the 2020 All-American Executive Team Best CEO in the natural gas industry.

Mr. Fusco served as Chief Executive Officer of Calpine Corporation (**"Calpine"**) from August 2008 to May 2014 and as Executive Chairman of Calpine from May 2014 through May 11, 2016. Mr. Fusco served as a member of the board of directors of Calpine from August 2008 until March 2018, when the sale of Calpine to an affiliate of Energy Capital Partners and a consortium of other investors was completed. Mr. Fusco was recruited by Calpine's key shareholders in 2008, just as that company was emerging from bankruptcy. Calpine grew to become America's largest generator of electricity from natural gas, safely and reliably meeting the needs of an economy that demands cleaner, more fuel-efficient and dependable sources of electricity. As Chief Executive Officer of Calpine, Mr. Fusco managed a team of approximately 2,300 employees and led one of the largest purchasers of natural gas in America, a successful developer of new gas-fired power generation facilities and a company that prudently managed the inherent commodity trading and balance sheet risks associated with being a merchant power producer.

Mr. Fusco's career of over 40 years in the energy industry began with his employment at Pacific Gas & Electric Company upon graduation from California State University, Sacramento with a Bachelor of Science in Mechanical Engineering in 1984. He joined Goldman Sachs 13 years later as a Vice President with responsibility for commodity trading and marketing of wholesale electricity, a role that led to the creation of Orion Power Holdings, an independent power producer that Mr. Fusco helped found with backing from Goldman Sachs, where he served as President and Chief Executive Officer from 1998-2002. In 2004, he was asked to serve as Chairman and Chief Executive Officer of Texas Genco LLC by a group of private institutional investors, and successfully managed the transition of that business from a subsidiary of a regulated utility to a strong and profitable independent company, generating a more than 5-fold return for shareholders upon its merger with NRG in 2006. Mr. Fusco is currently on the board of directors of the American-Italian Cancer Foundation, a non-profit organization supporting cancer research and education. It was determined that Mr. Fusco should serve as a director of our general partner because of his prior experience leading successful energy industry companies and his perspective as President and Chief Executive Officer of Cheniere.

Brian Baker

Director of our general partner and a member of the Executive Committee

Mr. Baker is an Operating Partner and Regional Head of North America for Brookfield Infrastructure Group, where he is responsible for evaluating investment opportunities, including oversight and investment strategy in the region. Mr. Baker served as Interim President and Chief Executive Officer of Inter Pipeline Ltd., a major petroleum transportation and natural gas liquids processing business based in Canada, from October 2021 to September 2023, and has served as Chairman of the Board of Inter Pipeline since November 2023. Prior to joining Brookfield in 2007, Mr. Baker was Vice President and Chief Financial Officer for several oil and gas production companies in Western Canada. He was previously a Partner at Collins Barrow Chartered Accountants, where he focused on advisory work in the oil and gas sector. Mr. Baker holds a Bachelor of Commerce degree from the University of Calgary and is a Chartered Professional Accountant. Mr. Baker brings experience as an executive officer for energy companies and insights from his advisory work in the oil and gas sector, and was appointed as a director of our general partner pursuant to the rights of CQP Holdco under the GP LLC Agreement. Mr. Baker has not held any other directorships in a company with a class of securities registered pursuant to Section 12 of the Exchange Act or subject to the requirements of Section 15(d) of such Act or any company registered as an investment company under the Investment Company Act during the past five years.

James R. Ball

Director of our general partner, Chairman of the Executive Committee and the CMI SPA Committee and a member of the Conflicts Committee

Mr. Ball served as a senior advisor to Tachebois Limited, an energy and equities advisory firm from 2011 to 2019. Mr. Ball served as a Non-Executive Director of Gas Strategies Group Ltd, a professional services company providing commercial energy advisory services, from September 2011 to June 2013. From 1988 through 2003, he served as Chief Executive and Chairman of Gas Strategies Group, a company he founded and where he spent his career advising on financing, developing, and operating many of the world’s largest LNG projects. From 2004 until August 2011, he also served as an Executive Director of Gas Strategies Group. Mr. Ball has over 40 years of experience in the LNG business. Mr. Ball is a Fellow of the Energy Institute and Companion of the Institute of Gas Engineers and Managers. Mr. Ball received a B.A. in Economics from the University of Colorado and an M.S. from Bayes Business School. It was determined that Mr. Ball should serve as a director of our general partner because of his background as an advisor in the energy industry. Mr. Ball has not held any other directorships in a company with a class of securities registered pursuant to Section 12 of the Exchange Act or subject to the requirements of Section 15(d) of such Act or any company registered as an investment company under the Investment Company Act of 1940 (the **“Investment Company Act”**) during the past five years.

Zach Davis

Executive Vice President and Chief Financial Officer of our general partner, Director of our general partner and a member of the Executive Committee

Mr. Davis has served as Executive Vice President and Chief Financial Officer of Cheniere and our general partner since February 2022, and previously served as Senior Vice President and Chief Financial Officer from August 2020 to February 2022. Mr. Davis also serves as a director of the Cheniere Foundation. Institutional Investor recognized Mr. Davis as the All-America Executive Team Best CFO in Energy - Natural Gas & Master Limited Partnership Sector for 2023 and 2024 by the buy-side and sell-side investor community.

Mr. Davis joined Cheniere in November 2013. He previously served as Senior Vice President, Finance from February 2020 to August 2020 and as Vice President, Finance and Planning from October 2016 to February 2020. Mr. Davis has over 17 years of finance experience, primarily in the LNG, power, renewable energy, midstream and infrastructure sectors. Prior to joining Cheniere, Mr. Davis held energy investment banking and project finance roles at Credit Suisse, Marathon Capital and HSH Nordbank. Mr. Davis received a B.S. in Economics from Duke University. It was determined that Mr. Davis should serve as a director of our general partner because of his background in energy finance and his perspective as Executive Vice President and Chief Financial Officer of Cheniere. Mr. Davis has not held any other directorships in a company with a class of securities registered pursuant to Section 12 of the Exchange Act or subject to the requirements of Section 15(d) of such Act or any company registered as an investment company under the Investment Company Act during the past five years.

Christopher Dell'Amore

Director of our general partner and a member of the Executive Committee

Mr. Dell'Amore is a Principal in the Infrastructure Group for Blackstone Inc. Since joining Blackstone, Mr. Dell'Amore has been involved in the execution of Blackstone's investment in Mundys, while also serving on the board of directors of Tallgrass Energy since 2023. Prior to joining Blackstone, Mr. Dell'Amore worked at Morgan Stanley Infrastructure Partners (MSIP) and Fortress Investment Group, focusing on investments in the energy, power and transportation sectors. Prior to that, Mr. Dell'Amore was an Analyst at Société Générale in the Energy group. Mr. Dell'Amore previously served as a director of Höegh LNG Holdings Ltd., a leading owner and operator of floating storage and regasification units and LNG carriers, as a Board Alternate/Observer from May 2021 to September 2021. Mr. Dell'Amore received a B.A. in Economics and Spanish Language & Literature from Colgate University, where he graduated magna cum laude and with honors, an M.B.A. from The Wharton School at the University of Pennsylvania and an M.A. in International Studies (Latin America) from The Lauder Institute at the University of Pennsylvania. Mr. Dell'Amore also serves as a board member of America Needs You (New York). Mr. Dell'Amore was appointed as a director of our general partner pursuant to the rights of CQP Holdco under the GP LLC Agreement, and brings energy and infrastructure investment experience to the board.

Corey Grindal

Director and Executive Vice President and Chief Operating Officer of our general partner

Mr. Grindal has served as Executive Vice President and Chief Operating Officer of Cheniere and Cheniere Partners GP since January 2023. Mr. Grindal previously served as Executive Vice President, Worldwide Trading from November 2020 to January 2023. Mr. Grindal served as Senior Vice President, Gas Supply from September 2016 to September 2020, after joining Cheniere in June of 2013 as Vice President of Supply. Mr. Grindal was brought in to develop the required infrastructure needed for firm and reliable deliveries to Cheniere's LNG terminals, establish the required relationships with the United States' producer community, and set up the needed systems, processes and personnel for Cheniere to be the premier United States LNG exporter. Mr. Grindal has over 30 years of experience in pipeline construction and operations, project management and natural gas and power trading. Prior to joining Cheniere, Mr. Grindal was with Deutsche Bank and was responsible for physical and financial trading. Prior to Deutsche Bank, Mr. Grindal held positions with Louis Dreyfus and the Tenneco/ El Paso companies. Mr. Grindal holds a B.S. degree in Mechanical Engineering with Honors from the University of Texas at Austin. It was determined that Mr. Grindal should serve as a director of our general partner because of his background in the energy, oil and natural gas trading and marketing industry. Mr. Grindal has not held any other directorships in a company with a class of securities registered pursuant to Section 12 of the Exchange Act or subject to the requirements of Section 15(d) of such Act or any company registered as an investment company under the Investment Company Act during the past five years.

Taylor Johnson

Deputy General Counsel and Assistant Secretary of our general partner, Director of our general partner and a member of the CMI SPA Committee

Mr. Johnson has served as Deputy General Counsel of Cheniere and Cheniere Partners GP since March 2023. Mr. Johnson joined Cheniere in April 2017 as Assistant General Counsel, providing legal support and strategic advice for Cheniere's commercial transactions, project development activities, and climate and sustainability initiatives. Mr. Johnson has over 15 years of experience in LNG project development, LNG marketing, LNG trading, and LNG operations. Prior to joining Cheniere, Mr. Johnson held senior legal and commercial positions with Veresen Inc. and BG Group. Mr. Johnson received a B.B.A. from Abilene Christian University and a J.D. from the University of Houston. It was determined that Mr. Johnson should serve as a director of our general partner because of his background in commercial transactions and his perspective as Deputy General Counsel of Cheniere. Mr. Johnson has not held any other directorships in a company with a class of securities registered pursuant to Section 12 of the Exchange Act or subject to the requirements of Section 15(d) of such Act or any company registered as an investment company under the Investment Company Act during the past five years.

Lon McCain

Director of our general partner, Chairman of the Audit Committee and a member of the Conflicts Committee

Mr. McCain was Executive Vice President and Chief Financial Officer of Ellora Energy Inc., a private, independent exploration and production company from July 2009 to August 2010. Prior to that, he was Vice President, Treasurer and Chief Financial Officer of Westport Resources Corporation, a publicly traded exploration and production company, from 2001 until the sale of that company to Kerr-McGee Corporation in 2004. From 1992 until joining Westport, Mr. McCain was Senior Vice President and Principal of Petrie Parkman & Co., an investment banking firm specializing in the oil and gas industry. From 1978 until joining Petrie Parkman, Mr. McCain held senior financial management positions with Presidio Oil Company, Petro-Lewis Corporation and Ceres Capital. He is currently on the board of directors of Crescent Energy Company, a publicly traded energy investment company. Mr. McCain previously served on the board of directors of Continental Resources, Inc., a publicly traded oil and natural gas exploration and production company, from 2006 through its private acquisition in 2022. He also previously served on the board of directors of Contango Oil and Gas Company, which combined with Independence Energy, LLC to form Crescent Energy Company in December 2021. Mr. McCain received a B.S. in Business Administration and an M.B.A. in Finance from the University of Denver. Mr. McCain was also an Adjunct Professor of Finance at the University of Denver from 1982 to 2005. It was determined that Mr. McCain should serve as a director of our general partner because of his experience as a chief financial officer for energy companies and his background as an investment banker in the energy industry.

Vincent Pagano, Jr.

Director of our general partner, Chairman of the Conflicts Committee and a member of the Audit Committee

Mr. Pagano served as a senior corporate partner of Simpson Thacher & Bartlett LLP, a law firm, with a focus on capital markets transactions and public company advisory matters from 1981 until his retirement at the end of 2012. Mr. Pagano earned a law degree, cum laude, from Harvard Law School and a B.S. in Engineering, summa cum laude, from Lehigh University and an M.S. in Engineering from the University of California, Berkeley. Mr. Pagano also serves as a director of Hovnanian Enterprises, Inc., a publicly traded homebuilding company, and served as a director of L3 Technologies, Inc., an aerospace and defense company, from 2013 until its merger with Harris Corporation in June 2019. It was determined that Mr. Pagano should serve as a director of our general partner because of his capital markets expertise and his experience as an advisor to public companies on a variety of corporate matters.

Scott Peak

Director of our general partner, member of the Executive Committee and a member of the CMI SPA Committee

Mr. Peak is a Managing Partner and Head of North America for Brookfield’s Infrastructure Group. In this role, he is responsible for regional oversight and investment strategy leadership in the Americas and is involved in the screening and evaluation of global investment initiatives. Mr. Peak previously served as Chief Investment Officer for North America for Brookfield’s Infrastructure Group, where he was responsible for infrastructure investments, and is head of the Houston office. Prior to joining Brookfield in January 2016, Mr. Peak spent a decade at Macquarie Group Ltd., where he focused on the infrastructure sector. Previously, Mr. Peak worked in the mergers and acquisitions group at Dresdner Kleinwort Wasserstein in New York. Mr. Peak previously served as a director of Cheniere Energy, Inc. from April 2022 to April 2023 and the general partner of Cheniere Partners from September 2020 to April 2022. Mr. Peak holds a Master of Finance with distinction from INSEAD and a B.A. in Economics from Bates College. Mr. Peak has significant energy and infrastructure investment experience, and was appointed as a director of our general partner pursuant to the rights of CQP Holdco under the GP LLC Agreement. Mr. Peak has not held any other directorships in a company with a class of securities registered pursuant to Section 12 of the Exchange Act or subject to the requirements of Section 15(d) of such Act or any company registered as an investment company under the Investment Company Act during the past five years.

Oliver G. Richard, III

Director of our general partner and a member of the Audit Committee and Conflicts Committee

Mr. Richard is the owner and president of Empire of the Seed, LLC, a private consulting firm in the energy and management industries. Mr. Richard served as Chairman, President and Chief Executive Officer of Columbia Energy Group, a natural gas company, from 1995 until 2000, and as a director of Buckeye Partners, L.P., a publicly traded petroleum product pipeline and terminal company, from 2009 through its acquisition in 2019. Mr. Richard was a Commissioner on the FERC from 1982 until 1985. Mr. Richard served as a director of American Electric Power Company, Inc., a publicly traded electric utility, from January 2013 until September 2023. Mr. Richard received a B.S. in Journalism, a J.D. from Louisiana State University and a Master of Law in Taxation from Georgetown University. It was determined that Mr. Richard should serve as a director of our general partner because of his extensive background in the energy industry, including his experience in both the public and private sectors of the energy industry.

Code of Ethics

Our Code of Business Conduct and Ethics covers a wide range of business practices and procedures and furthers our fundamental principles of honesty, loyalty, fairness and forthrightness. The Code of Business Conduct and Ethics was approved by the directors of our general partner. Our Code of Business Conduct and Ethics, which is applicable to all of our directors, officers and employees, is posted at *https://cqpir.cheniere.com/company-information/governance-documents.* We also intend to post any changes to or waivers of our Code of Business Conduct and Ethics for the executive officers of our general partner on our website.

Delinquent Section 16(a) Reports

Section 16 of the Exchange Act requires the directors and executive officers of our general partner and persons who own more than 10% of a registered class of our equity securities to file initial reports of ownership and reports of changes in ownership with the SEC. Such persons are required by SEC regulation to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of such forms furnished to us and written representations from the directors and executive officers of our general partner (or otherwise based on our knowledge), we believe that all Section 16(a) filing requirements were met during 2023 in a timely manner.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Our general partner has paid no cash compensation to its executive officers since its inception. All of the executive officers of our general partner are also executive officers of Cheniere. Cheniere compensates these officers for the performance of their duties as executive officers of Cheniere, which includes managing our partnership. Cheniere does not allocate this compensation between services for us and services for Cheniere and its affiliates. Instead, an affiliate of Cheniere provides us various general and administrative services for our benefit, such as technical, commercial, regulatory, financial, accounting, treasury, tax and legal staffing and related support services, pursuant to a services agreement for which we pay a quarterly non-accountable overhead reimbursement charge of $3 million (adjusted for inflation). For a description of the services agreement, see Note 14—Related Party Transactions of our Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

In 2007, the board of directors of our general partner adopted the Cheniere Energy Partners, L.P. Long-Term Incentive Plan for employees, consultants and directors of our general partner, employees of its affiliates and consultants to its subsidiaries. The purpose of the plan is to enhance attraction and retention of qualified individuals who are essential for the successful operation of our partnership and to encourage them to align their interests with our interests through an equity ownership stake in us. The plan allows for the grant of options, restricted units, phantom units and unit appreciation rights. Up to 1,250,000 units may be granted under the plan. The only awards that have been granted under the plan have been made to the non-management directors of our general partner in the form of phantom units to be settled, at the director's election, in common units, cash or in equal amounts over a four-year vesting period.

Compensation Committee Report

As discussed above, the board of directors of our general partner does not have a compensation committee. In fulfilling its responsibilities, the board of directors of our general partner, acting in lieu of a compensation committee, has reviewed and discussed the Compensation Discussion and Analysis with management. Based on this review and discussion, the board of directors of our general partner recommended that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

By the members of the board of directors of our general partner:

Jack A. Fusco
Brian Baker
James R. Ball
Zach Davis
Christopher Dell'Amore
Corey Grindal
Taylor Johnson
Lon McCain
Vincent Pagano, Jr.
Scott Peak
Oliver G. Richard, III

Compensation Committee Interlocks and Insider Participation

As discussed above, the board of directors of our general partner does not have a compensation committee. If any compensation is to be paid to our general partners' officers, the compensation would be reviewed and approved by the entire board of directors of our general partner because they perform the functions of a compensation committee in the event such committee is needed. None of the directors or executive officers of our general partner served as a member of a compensation committee of another entity that has or has had an executive officer who served as a member of the board of directors of our general partner during 2023.

Director Compensation

On July 22, 2014, the board of directors of our general partner approved an annual fee of $70,000 to each non-management director of our general partner for services as a director effective pro-rata as of the date of the approval. Also approved were annual fees of $30,000 for the chairman of the audit committee; $15,000 for the members of the audit committee other than the chairman; $10,000 for the chairman of the conflicts committee; $2,500 per meeting for the members of the conflicts committee, including the chairman; $10,000 for the chairman of the executive committee; $2,500 per meeting for the non-employee members of the executive committee, including the chairman; and $30,000 for the chairman of the CMI SPA Committee. All directors' fees are pro-rated from the date of election to the board and are payable quarterly.

In addition to the annual fees paid to the non-management directors, Messrs. Ball, McCain, Pagano and Richard each receive 3,000 phantom units annually. Vesting will occur for one-fourth of the phantom units on each anniversary of the grant date beginning on the first anniversary of the grant date. Upon vesting, the phantom units will be payable, at the director's election, in common units, cash in an amount equal to fair market value of a common unit on such date, or an equal amount of both. The directors receive no distributions, and no distributions accrue, on the outstanding phantom units. Mr. Baker serves as an Operating Partner for Brookfield's Infrastructure Group, Mr. Dell'Amore serves as a Principal in the Infrastructure Group for Blackstone Inc. and Mr. Peak serves as a Managing Partner and Head of North America for Brookfield's Infrastructure Group. They do not receive additional compensation for service as directors.

The following table shows the compensation paid for service as a member of the board of directors of our general partner for the 2023 fiscal year:

Name	Fees Earned or Paid in Cash	Unit Awards (1)	Option Awards	Non-Equity Incentive Plan Compensation	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation	Total
Jack A. Fusco (2)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Brian Baker (3)(4)	—	—	—	—	—	—	—
James R. Ball (5)	112,500	159,780	—	—	—	—	272,280
Zach Davis (2)	—	—	—	—	—	—	—
Christopher Dell'Amore (3)(4)	—	—	—	—	—	—	—
Corey Grindal (2)	—	—	—	—	—	—	—
Taylor Johnson (2)(3)	—	—	—	—	—	—	—
Adam Kuhnley (3)(4)	—	—	—	—	—	—	—
Lon McCain (6)	100,000	134,730	—	—	—	—	234,730
Mark Murski (3)(4)	—	—	—	—	—	—	—
Vincent Pagano, Jr. (7)	95,000	177,900	—	—	—	—	272,900
Scott Peak (3)(4)	—	—	—	—	—	—	—
Oliver G. Richard, III (8)	85,000	159,780	—	—	—	—	244,780
Matthew Runkle (3)(4)	—	—	—	—	—	—	—
Tim Wyatt (2)(3)	—	—	—	—	—	—	—

(1) Reflects aggregate grant date fair value. The phantom units are to be settled, at the director's election, in common units, cash, or an equal amount of both. The units are valued using the closing unit price on the date of grant and are revalued on a quarterly basis through the date of vesting.

(2) Messrs. Fusco, Davis and Grindal served as executive officers of our general partner and as executive officers of Cheniere during fiscal year 2023. Mr. Johnson served as an officer of our general partner and as an officer of Cheniere since June 28, 2023. Mr. Wyatt served as an officer of our general partner and as an executive officer of Cheniere from January 1 until June 28, 2023. Cheniere compensates these officers for the performance of their duties as employees of Cheniere, which includes managing our partnership. They do not receive additional compensation for service as directors.

(3) Effective as of January 31, 2023, Messr. Dell'Amore was appointed to the board of directors of our general partner and Messr. Kuhnley resigned as a member of the board of directors of our general partner. Effective April 4, 2023, Messrs. Baker and Peak were appointed to the board of directors of our general partner and Messrs. Murski and Runkle each resigned as a member of the board of directors of our general partner. Effective as of June 28, 2023, Messr. Johnson was appointed to the board of directors of our general partner and Messr. Wyatt resigned as a member of the board of directors of our general partner.

(4) Messrs. Baker, Dell'Amore, Kuhnley, Murski, Peak, and Runkle are employees of Blackstone or Brookfield, as applicable. They do not receive additional compensation for service as directors.

(5) Mr. Ball was granted 3,000 phantom units in 2023 with a grant date fair value of $159,780. In addition, Mr. Ball received $119,835 in cash and 750 common units on account of 3,000 phantom units granted in earlier years that vested in 2023. As of December 31, 2023, he held 7,500 phantom units and 6,750 common units for a total of 14,250 units.

(6) Mr. McCain was granted 3,000 phantom units in 2023 with a grant date fair value of $134,730. In addition, Mr. McCain received $33,683 in cash and 2,250 common units on account of 3,000 phantom units granted in earlier years that vested in 2023. As of December 31, 2023, he held 7,500 phantom units and 13,875 common units for a total of 21,375 units.

(7) Mr. Pagano was granted 3,000 phantom units in 2023 with a grant date fair value of $177,900. In addition, Mr. Pagano received $88,950 in cash and 1,500 common units on account of 3,000 phantom units granted in earlier years that vested in 2023. As of December 31, 2023, he held 7,500 phantom units and 11,625 common units for a total of 19,125 units.

(8) Mr. Richard was granted 3,000 phantom units in 2023 with a grant date fair value of $159,780. In addition, Mr. Richard received $79,890 in cash and 1,500 common units on account of 3,000 phantom units granted in earlier years that vested in 2023. As of December 31, 2023, he held 7,500 phantom units and 15,750 common units for a total of 23,250 units.

Indemnification of Directors

We have entered into indemnification agreements with each of our directors, which provide for indemnification with respect to all expenses and claims that a director incurs as a result of actions taken, or not taken, on our behalf while serving as a director, officer, employee, controlling person, selling unitholder, agent or fiduciary of Cheniere Partners GP or any of our subsidiaries. Pursuant to the agreements, no indemnification will generally be provided (1) for claims brought by the director, except for a claim of indemnity under the indemnification agreement, if we approve the bringing of such claim, or if the Delaware Limited Liability Company Act requires providing indemnification because our director has been successful on the merits of such claim, (2) for claims under Section 16(b) of the Exchange Act, or (3) if there has been a final judgment entered by a court determining that the director acted in bad faith, engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was unlawful. Indemnification will be provided to the extent permitted by law, Cheniere Partners GP's certificate of formation and limited liability company agreement, and to a greater extent if, by law, the scope of coverage is expanded after the date of the indemnification agreements. In all events, the scope of coverage will not be less than what was in existence on the date of the indemnification agreements.

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

The limited partner interest in our partnership is divided into units. As of February 16, 2024, the following units were outstanding: 484.0 million common units and 9.9 million general partner units.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, or "investment power," which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities, and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable. Except as indicated by footnote, the address for the beneficial owners listed below is 845 Texas Avenue, Suite 1250, Houston, Texas 77002.

Owners of More than Five Percent of Outstanding Units

The following table shows the beneficial owners known by us to own more than five percent of our common units and/or general partner units as of February 16, 2024:

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Percentage of Total Securities Beneficially Owned
Cheniere Energy, Inc. (1)	239,872,502	50%	51%
Blackstone Inc. (2)	203,984,605	42%	41%
Brookfield Asset Management Inc. (3)	204,321,313	42%	41%

(1) Cheniere Energy, Inc. also owns 9,878,047 of our general partner units.

(2) Information is based on filings of Form 4 with the SEC on April 4, 2023 by CQP Rockies Platform LLC, CQP Common Holdco L.P., BIP Chinook Holdco L.L.C. (record holder of 338,242 common units), BIP-V Chinook Holdco II L.L.C. (record holder of 123,848 common units), BIP Holdings Manager, L.L.C., Blackstone Infrastructure Associates L.P., BIA GP L.P., BIA GP L.L.C., Blackstone Holdings III L.P., Blackstone Holdings III GP L.P., Blackstone Holdings III GP Management L.L.C., Blackstone Inc. (formerly known as The Blackstone Group Inc.), Blackstone Group Management L.L.C., and Stephen A. Schwarzman, which also lists CQP Holdco LP as the record holder of 190,070,316 common units and BIP-V Chinook Holdco L.L.C. (**"BIP-V"**) as the record holder of 13,170,436 common units. In addition, Harvest Fund Advisors LLC, an indirect subsidiary of Blackstone Inc., is the beneficial owner of 281,763 common units based on Schedule 13D/A filed with the SEC on September 28, 2020 by

Blackstone Inc. and its affiliates. The address of the various persons identified in this footnote is 345 Park Avenue, New York, New York 10154.

(3) Information is based on Schedule 13D filed with the SEC on September 30, 2020 and Form 4 filed with the SEC on June 9, 2021 by Brookfield Asset Management Inc. (**"Brookfield"**), BIF IV Cypress Aggregator (Delaware) LLC (**"BIF IV Cypress Aggregator"**), Brookfield Infrastructure Fund IV GP LLC (**"BIF"**), Brookfield Asset Management Private Institutional Capital Adviser (Canada), LP (**"BAMPIC Canada"**) and BAM Partners Trust (formerly known as Partners Limited) (**"Partners"**). Investment funds managed by Brookfield Public Securities Group LLC are the beneficial owners of 1,080,561 common units. 190,070,316 of the common units reported herein as being beneficially owned by the Reporting Persons are directly held by CQP Holdco LP. 13,170,436 of the common units reported herein as being beneficially owned by the Reporting Persons are directly held by BIP-V. CQP Target Holdco L.L.C. (formerly known as BX CQP Target Holdco L.L.C.) (**"Target Holdco"**) is the indirect equity holder of all of the equity interests in each of Blackstone CQP Common Holdco L.P. (**"Blackstone Common Holdco"**), CQP Holdco LP, and BX Rockies Platform Co LLC (**"BX Rockies"**) and, by virtue of its relationship with BIP-V, may be deemed to share beneficial ownership over the common units held directly by BIP-V. BIF IV Cypress Aggregator is a member of Target Holdco. BIF serves as the indirect general partner of BIF IV Cypress Aggregator. BAMPIC Canada serves as the investment adviser to BIF. Brookfield is the ultimate parent of Brookfield Infrastructure Fund III GP and BAMPIC Canada. As a result, Brookfield, BIF IV Cypress Aggregator, BIF, BAMPIC Canada and Partners may be deemed to beneficially own the common units held of record by each of Blackstone Common Holdco, CQP Holdco LP, BX Rockies and BIP-V. The address of the various persons identified in this footnote is 181 Bay Street, Suite 300, Brookfield Place, Toronto, Ontario M5J 2T3, Canada.

Directors and Executive Officers

The following table sets forth information with respect to our common units beneficially owned as of February 16, 2024, by each director and executive officer of our general partner and by all current directors and executive officers of our general partner as a group. On February 16, 2024, the current directors and executive officers of CQP beneficially owned an aggregate of 48,000 common units (less than 1% of the outstanding common units at the time).

The table also presents information with respect to Cheniere Energy, Inc.'s common stock beneficially owned as of February 16, 2024, by each current director and executive officer of our general partner and by all directors and executive officers of our general partner as a group. As of February 16, 2024, Cheniere Energy, Inc. had approximately 235 million shares of common stock outstanding.

	Cheniere Energy Partners, L.P.		Cheniere Energy, Inc.	
Name of Beneficial Owner	**Amount and Nature of Beneficial Ownership**	**Percent of Class**	**Amount and Nature of Beneficial Ownership**	**Percent of Class**
Jack A. Fusco	—	—%	724,063	*%
Zach Davis	—	—	102,597	*
Corey Grindal	—	—	143,667	*
Brian Baker (1)	—	—	—	—
James R. Ball	6,750	*	—	—
Christopher Dell'Amore (1)	—	—	—	—
Taylor Johnson	—	—	40,287	*
Lon McCain	13,875	*	—	—
Vincent Pagano, Jr.	11,625	*	—	—
Scott Peak (1)	—	—	—	—
Oliver G. Richard, III	15,750	*	—	—
All current directors and executive officers as a group (11 persons)	48,000	*%	1,010,614	*%

* Less than 1%

(1) Messrs. Baker, Dell'Amore, and Peak were appointed as directors of our general partner pursuant to the rights of CQP Holdco under the GP LLC Agreement to appoint certain directors to the board of directors of our general partner.

Equity Compensation Plan Information

In 2007, the board of directors of our general partner adopted the Cheniere Energy Partners, L.P. Long-Term Incentive Plan. The following table provides certain information as of December 31, 2023 with respect to this plan:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (1)	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column) (2)
Equity compensation plans approved by security holders	—	N/A	—
Equity compensation plans not approved by security holders	16,500	N/A	1,175,000
Total	16,500	N/A	1,175,000

(1) The phantom units that have been granted are payable, at the director's election, in common units, in cash at the time of vesting in an amount equal to the fair market value of a common unit on such date or an equal amount of both.

(2) The number of securities remaining available for issuance does not include securities reserved for issuance upon the vesting of unvested phantom units issued to directors for which such directors have made an irrevocable election to receive common units in lieu of cash.

For more information regarding the Long-Term Incentive Plan, see "Compensation Discussion and Analysis."

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

Related-Party Transactions

Prior to the completion of our initial public offering of common units in 2007, the managers of our general partner approved the distributions and payments to be made to our general partner and its affiliates in connection with our ongoing operations and, in the event of, our liquidation. During our operational stage, we will generally make cash distributions to our unitholders, including our affiliates, as described in Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities, of this annual report on Form 10-K. Upon our liquidation, our partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Procedures for Review, Approval and Ratification of Transactions with Related Persons

Under the audit committee charter, the audit committee of our general partner is required to review and approve all transactions or series of related financial transactions, arrangements or relationships between the partnership and any related-party, if the amount involved exceeds $120,000 and such transactions have not been reviewed by the conflicts committee of our general partner. The following related-party transactions are in addition to those related-party transactions described in Note 14—Related Party Transactions of our Notes to Consolidated Financial Statements which is herein incorporated by reference. Except as described below, such related-party transactions were approved by the members of the board of directors of our general partner, which includes each member of the audit committee.

In determining whether to approve or ratify a related party transaction, the audit committee of our general partner will apply the following standards and such other standards it deems appropriate:

- whether the related party transaction is on terms no less favorable than the terms generally available to an unaffiliated third party under the same or similar circumstances;
- whether the transaction is material to the Partnership or the related party; and
- the extent of the related person's interest in the transaction.

In addition, pursuant to our Code of Business Conduct and Ethics approved by the board of directors of our general partner, the directors, officers and employees of our general partner are expected to bring to the attention of the Compliance

Officer any conflict or potential conflict of interest. If a conflict or potential conflict of interest arises between us and a director, officer or any of our affiliates, the resolution of any such conflict or potential conflict should be addressed by the board in accordance with the provisions of our limited partnership agreement.

Independent Directors

Because we are a limited partnership, the NYSE American does not require our general partner's board of directors to be composed of a majority of directors who meet the criteria for independence required by NYSE American. The board of our general partner has determined that Messrs. Ball, McCain, Pagano and Richard are independent directors in accordance with the following NYSE American independence standards. A director would not be independent if any of the following relationships exists:

- a director who is, or during the past three years was, employed by the partnership, general partner or by any parent or subsidiary of the partnership or general partner, other than prior employment as an interim executive officer (provided the interim employment did not last longer than one year);
- a director who accepts, or has an immediate family member who accepts, any compensation from the partnership, general partner or any parent or subsidiary of the partnership or general partner in excess of $120,000 during any twelve consecutive-month period within the three years preceding the determination of independence, other than compensation for board or committee services, or compensation paid to an immediate family member who is a non-executive employee of the partnership, general partner or any parent or subsidiary of the partnership or general partner, among other exceptions;
- a director who is an immediate family member of an individual who is, or at any time during the past three years was, employed by the partnership, general partner or any parent or subsidiary of the partnership or general partner as an executive officer;
- a director who is, or has an immediate family member who is, a partner in, or a controlling shareholder or an executive officer of, any organization to which the partnership, general partner or any parent or subsidiary of the partnership or general partner made, or from which the partnership, general partner or any parent or subsidiary of the partnership or general partner received, payments (other than those arising solely from investments in our common units or payments under non-discretionary charitable contribution matching programs) that exceed 5% of the organization's consolidated gross revenues for that year, or $200,000, whichever is more, in any of the most recent three fiscal years;
- a director who is, or has an immediate family member who is, employed as an executive officer of another entity where at any time during the most recent three fiscal years any of the executive officers of the partnership, general partner or any parent or subsidiary of the partnership or general partner serves on the compensation committee of such other entity; or
- a director who is, or has an immediate family member who is, a current partner of the outside auditor of the partnership, general partner or parent or subsidiary of the partnership or general partner, or was a partner or employee of the outside auditor of the partnership, general partner or any parent or subsidiary of the partnership or general partner who worked on our audit at any time during any of the past three years.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered public accounting firm is KPMG LLP, Houston, Texas, Auditor Firm ID 185. The following table sets forth the fees billed by KPMG LLP for professional services rendered for 2023 and 2022 (in millions):

	Fiscal 2023	Fiscal 2022
Audit Fees	$ 3	$ 3

Audit Fees—Audit fees for 2023 and 2022 include fees associated with the integrated audit of our annual Consolidated Financial Statements, reviews of our interim Consolidated Financial Statements and services performed in connection with registration statements and debt offerings, including comfort letters and consents.

Audit-Related Fees—There were no audit-related fees in 2023 and 2022.

Tax Fees—There were no tax fees in 2023 and 2022.

Other Fees—There were no other fees in 2023 and 2022.

Auditor Pre-Approval Policy and Procedures

Under the audit committee's charter, the audit committee is required to review and approve in advance all audit and lawfully permitted non-audit services to be provided by the independent accountants and the fees for such services. Pre-approval of non-audit services (other than review and attestation services) shall not be required if such services fall within exceptions established by the SEC. All audit and non-audit services provided to us during the fiscal years ended December 31, 2023 and 2022 were pre-approved.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements and Exhibits

(1) Financial Statements—Cheniere Energy Partners, L.P.:

(2) Financial Statement Schedules:

(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 Partnership 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	Contribution and Conveyance Agreement, by and among the Partnership, Cheniere LNG Holdings, LLC, Cheniere Partners GP, Cheniere Investments, Sabine Pass LNG-GP, Inc. and Sabine Pass LP, effective as of March 26, 2007	CQP	8-K	10.4	3/26/2007
2.2	Amended and Restated Purchase and Sale Agreement, dated as of August 9, 2012, by and among the Partnership, Cheniere Pipeline Company, Grand Cheniere Pipeline, LLC and Cheniere	CQP	8-K	10.2	8/9/2012

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
3.1	Certificate of Limited Partnership of the Partnership	CQP (SEC File No. 333-139572)	S-1	3.1	12/21/2006
3.2	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated as of February 14, 2017	CQP	8-K	3.1	2/21/2017
3.3	Certificate of Formation of Cheniere Partners GP	CQP (SEC File No. 333-139572)	S-1	3.3	12/21/2006
3.4	Third Amended and Restated Limited Liability Company Agreement of Cheniere Partners GP, dated as of August 9, 2012	CQP	8-K	3.2	8/9/2012
4.1	Form of common unit certificate (Included as Exhibit A to Exhibit 3.2 above)	CQP	8-K	3.1	2/21/2017
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
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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
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	CQP	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)	CQP	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	CQP	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)	CQP	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	CQP	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)	CQP	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	CQP	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)	CQP	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	CQP	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)	CQP	10-K	4.32	2/24/2022
4.34	Indenture, dated as of September 18, 2017, between the Partnership, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/18/2017
4.35	First Supplemental Indenture, dated as of September 18, 2017, between the Partnership, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.2	9/18/2017
4.36	Second Supplemental Indenture, dated as of September 11, 2018, among the Partnership, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/12/2018
4.37	Third Supplemental Indenture, dated as of September 12, 2019, among the Partnership, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/12/2019
4.38	Form of 4.500% Senior Notes due 2029 (Included as Exhibit A-1 to Exhibit 4.37 above)	CQP	8-K	4.1	9/12/2019
4.39	Fourth Supplemental Indenture, dated as of November 5, 2020, between the Partnership, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	10-Q	4.1	11/6/2020
4.40	Fifth Supplemental Indenture, dated as of March 11, 2021, among the Partnership, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	3/11/2021
4.41	Form of 4.000% Senior Notes due 2031 (Included as Exhibit A-1 to Exhibit 4.40 above)	CQP	8-K	4.1	3/11/2021
4.42	Sixth Supplemental Indenture, dated as of September 27, 2021, among the Partnership, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/27/2021
4.43	Form of 3.25% Senior Notes due 2032 (Included as Exhibit A-1 to Exhibit 4.42 above)	CQP	8-K	4.1	9/27/2021

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
4.44	Seventh Supplemental Indenture, dated as of September 27, 2021, among the Partnership, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	10/1/2021
4.45	Eighth Supplemental Indenture, dated as of June 21, 2023, among the Partnership, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	6/21/2023
4.46	Form of 5.950% Senior Notes due 2033 (Included as Exhibit A to Exhibit 4.45 above)	CQP	8-K	4.1	6/21/2023
4.47*	Description of the Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934				
10.1	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
10.2	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
10.3	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
10.4	Credit and Guaranty Agreement, dated as of June 23, 2023, among the Partnership, as borrower, certain subsidiaries of the Partnership, 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	CQP	10-Q	10.2	8/3/2023
10.5†	Cheniere Energy Partners, L.P. 2007 Long-Term Incentive Plan	CQP	8-K	10.3	3/26/2007
10.6†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (2012 Reload Award)	CQP	10-Q	10.9	11/2/2012
10.7†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan	CQP	10-Q	10.8	11/2/2012
10.8†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Units Settlement)	CQP	10-K	10.41	2/20/2015
10.9†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Reload Units Settlement)	CQP	10-K	10.42	2/20/2015
10.10†	Form of Indemnification Agreement for officers and/or directors of Cheniere Partners GP	CQP	10-Q	10.2	11/3/2022
10.11	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.)	CQP	8-K	10.1	11/9/2018
10.12	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	CQP	10-Q	10.4	8/8/2019

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.13	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	CQP	10-Q	10.2	11/1/2019
10.14	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	CQP	10-K	10.34	2/25/2020
10.15	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	CQP	10-Q	10.4	4/30/2020
10.16	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	CQP	10-Q	10.2	8/6/2020

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.17	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-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	CQP	10-Q	10.1	11/6/2020
10.18	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	CQP	10-K	10.34	2/24/2021
10.19	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	CQP	10-Q	10.2	5/4/2021

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.20	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	CQP	10-Q	10.1	8/5/2021
10.21	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
10.22	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	CQP	10-K	10.39	2/24/2022
10.23	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	CQP	10-Q	10.1	5/4/2022
10.24	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	CQP	10-Q	10.2	8/4/2022

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.25	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	CQP	10-Q	10.1	11/3/2022
10.26	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	CQP	10-K	10.44	2/23/2023
10.27	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	CQP	10-Q	10.1	5/2/2023
10.28	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	CQP	10-Q	10.1	11/2/2023
10.29	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
10.30	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
10.31	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
10.32	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	CQP	10-Q	10.8	8/3/2023
10.33	LNG Sale and Purchase Agreement (FOB), dated December 11, 2011, between SPL (Seller) and GAIL (India) Limited (Buyer)	CQP	8-K	10.1	12/12/2011

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.34	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between SPL (Seller) and GAIL (India) Limited (Buyer)	CQP	10-K	10.18	2/22/2013
10.35	Letter agreement regarding change from LIBOR to SOFR, dated June 16, 2023, to LNG Sale and Purchase Agreement, dated December 11, 2011, between SPL and GAIL (India) Limited, as amended	CQP	10-Q	10.6	8/3/2023
10.36	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
10.37	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	CQP	10-Q	10.5	8/3/2023
10.38	LNG Sale and Purchase Agreement (FOB), dated January 30, 2012, between SPL (Seller) and Korea Gas Corporation (Buyer)	CQP	8-K	10.1	1/30/2012
10.39	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between SPL (Seller) and Korea Gas Corporation (Buyer)	CQP	10-K	10.19	2/22/2013
10.40	Letter agreement regarding change from LIBOR to SOFR, dated June 30, 2023, to LNG Sale and Purchase Agreement, dated January 30, 2012, between SPL and Korea Gas Corporation, as amended	CQP	10-Q	10.7	8/3/2023
10.41	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between SPL (Seller) and Cheniere Marketing, LLC (Buyer)	SPL	8-K	10.1	8/11/2014
10.42	Letter agreement, dated December 8, 2016, amending the Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between SPL and Cheniere Marketing International LLP (as assignee of Cheniere Marketing, LLC)	SPL	10-K	10.14	2/24/2017
10.43	Amendment No. 1 of Amended and Restated LNG Sale and Purchase Agreement, dated May 3, 2019, by and between SPL and Cheniere Marketing International LLP	CQP	10-Q	10.1	5/9/2019
10.44	Letter Agreement, dated August 4, 2021, regarding the Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between SPL and Cheniere Marketing International LLP (as assignee of Cheniere Marketing, LLC)	CQP	10-Q	10.2	8/5/2021
10.45	Letter Agreement, dated November 24, 2021, regarding the Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between SPL and Cheniere Marketing International LLP (as assignee of Cheniere Marketing, LLC)	CQP	8-K	10.1	11/26/2021
10.46	Letter agreement regarding change from LIBOR to SOFR, dated June 26, 2023, to Amended and Restated LNG Sale and Purchase Agreement (FOB) between SPL and Cheniere Marketing International LLP, dated August 5, 2014, as amended	CQP	10-Q	10.9	8/3/2023
10.47	LNG Sale and Purchase Agreement (Tourmaline Oil Marketing Corp), dated June 15, 2022, between SPL and Cheniere Marketing International LLP	CQP	10-Q	10.3	11/3/2022
10.48	Management Services Agreement, dated May 14, 2012, by and between Cheniere Terminals and SPL	CQP	8-K	10.6	5/15/2012
10.49	Amendment to Management Services Agreement, dated September 28, 2015, between Cheniere Terminals and SPL	SPL	10-Q/A	10.8	11/9/2015

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.50	Amended and Restated Management Services Agreement, dated as of August 9, 2012, by and between Cheniere Terminals and SPLNG	CQP	10-Q	10.6	11/2/2012
10.51	Management Services Agreement, dated May 27, 2013, by and between Cheniere Terminals and CTPL	CQP	10-Q	10.2	8/2/2013
10.52	Operation and Maintenance Agreement (Sabine Pass Liquefaction Facilities), dated May 14, 2012, by and between Cheniere LNG O&M Services, LLC, Cheniere Partners GP and SPL	CQP	8-K	10.5	5/15/2012
10.53	Assignment and Assumption Agreement (Sabine Pass Liquefaction O&M Agreement), dated as of November 20, 2013, by and between Cheniere Partners GP and Cheniere Investments	Cheniere Holdings	S-1/A	10.76	12/2/2013
10.54	Amendment to Operation and Maintenance Agreement (Sabine Pass Liquefaction Facilities), dated September 28, 2015, by and among Cheniere LNG O&M Services, LLC, Cheniere Investments and SPL	SPL	10-Q/A	10.7	11/9/2015
10.55	Amended and Restated Operation and Maintenance Agreement (Sabine Pass LNG Facilities), dated as of August 9, 2012, by and among Cheniere Partners GP, Cheniere LNG O&M Services, LLC, and SPLNG	CQP	10-Q	10.5	11/2/2012
10.56	Assignment and Assumption Agreement (Sabine Pass LNG O&M Agreement), dated as of November 20, 2013, by and between Cheniere Partners GP and Cheniere Investments	Cheniere Holdings	S-1/A	10.75	12/2/2013
10.57	Amended and Restated Management and Administrative Services Agreement, dated as of August 9, 2012, by and between Cheniere Terminals, the Partnership and Cheniere	CQP	10-Q	10.4	11/2/2012
10.58	Amended and Restated Operation and Maintenance Services Agreement (Cheniere Creole Trail Pipeline), dated May 27, 2013, by and between CTPL and Cheniere Partners GP	CQP	10-Q	10.1	8/2/2013
10.59	Assignment and Assumption Agreement (Creole Trail O&M Agreement), dated as of November 20, 2013, between Cheniere Partners GP and Cheniere Investments	Cheniere Holdings	S-1/A	10.74	12/2/2013
10.60	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
10.61	Amended and Restated Services and Secondment Agreement, dated as of August 9, 2012, between Cheniere LNG O&M Services, LLC and Cheniere Partners GP	CQP	10-Q	10.3	11/2/2012
10.62	Assignment and Assumption Agreement (Services and Secondment Agreement), dated as of November 20, 2013, by and between Cheniere Partners GP and Cheniere Investments	Cheniere Holdings	S-1/A	10.73	12/2/2013
10.63	Investors' and Registration Rights Agreement, dated as of July 31, 2012, by and among Cheniere, Cheniere Partners GP, the Partnership, 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
21.1*	Subsidiaries of the Partnership				
22.1*	List of Issuers and Guarantor Subsidiaries				
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 Partners, L.P. 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. 333-191298), SPL (SEC File No. 333-192373) and SPLNG (SEC File No. 333-138916), as applicable, unless otherwise indicated.

* Filed herewith.

** Furnished herewith.

† Management contract or compensatory plan or arrangement.

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED STATEMENTS OF INCOME

(in millions)

	Year Ended December 31,		
	2023	2022	2021
Operating costs and expenses			
General and administrative expense	$ (4)	$ (4)	$ (3)
General and administrative expense—affiliate	(16)	(15)	(14)
Amortization of capitalized interest associated to investment in subsidiaries	(3)	(3)	(3)
Total operating costs and expenses	(23)	(22)	(20)
Other income (expense)			
Interest expense, net of capitalized interest	(218)	(176)	(199)
Loss on modification or extinguishment of debt	—	—	(97)
Other income	32	14	1
Equity income of subsidiaries	4,463	2,682	1,946
Total other income	4,277	2,520	1,651
Net income	$ 4,254	$ 2,498	$ 1,631

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

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED BALANCE SHEETS

(in millions)

	December 31,	
	2023	2022
ASSETS		
Current assets		
Cash and cash equivalents	$ 572	$ 899
Trade receivables—affiliates	1	—
Other current assets	1	1
Total current assets	574	900
Capitalized interest associated to investment in subsidiaries, net of accumulated amortization	74	75
Debt issuance costs, net of accumulated amortization	7	3
Investment in subsidiaries	4,204	1,106
Total assets	$ 4,859	$ 2,084
LIABILITIES AND PARTNERS' DEFICIT		
Current liabilities		
Accrued liabilities	$ 97	$ 53
Due to affiliates	4	3
Total current liabilities	101	56
Long-term debt, net of debt issuance costs	5,542	4,159
Partners' deficit	(784)	(2,131)
Total liabilities and partners' deficit	$ 4,859	$ 2,084

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

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED STATEMENTS OF CASH FLOWS

(in millions)

	Year Ended December 31, 2023	2022	2021
Cash flows provided by operating activities	$ 2,682	$ 2,514	$ 1,732
Cash flows from investing activities			
Capitalized interest associated to investment in subsidiaries	(2)	(1)	(1)
Investments in subsidiaries	(1,470)	(454)	(1,009)
Distributions received from subsidiaries	—	601	403
Payments of financing costs of subsidiary	(2)	—	—
Net cash provided by (used in) investing activities	(1,474)	146	(607)
Cash flows from financing activities			
Proceeds from issuance of debt	1,397	—	2,700
Redemptions and repayments of debt	—	—	(2,600)
Debt issuance and other financing costs	(25)	—	(35)
Debt extinguishment costs	—	—	(73)
Distributions to owners	(2,907)	(2,635)	(1,451)
Net cash used in financing activities	(1,535)	(2,635)	(1,459)
Net increase (decrease) in cash and cash equivalents	(327)	25	(334)
Cash and cash equivalents—beginning of period	899	874	1,208
Cash and cash equivalents—end of period	$ 572	$ 899	$ 874

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

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CHENIERE ENERGY PARTNERS, L.P.

NOTES TO CONDENSED FINANCIAL STATEMENTS

NOTE 1—BASIS OF PRESENTATION

The Condensed Financial Statements represent the financial information required by Securities and Exchange Commission Regulation S-X 5-04 for CQP.

In the Condensed Financial Statements, CQP's investments in subsidiaries are presented at the net amount attributable to CQP under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded on the Condensed Balance Sheets. Our share of net income or loss from operations of the subsidiaries is reported as equity income or loss of subsidiaries. In our Condensed Statements of Cash Flows, we apply the cumulative earnings approach when determining whether distributions received from subsidiaries shall be treated as returns of or returns on investment. Under this approach, all distributions received by CQP are deemed returns on investment and classified as cash inflows from operating activities unless the cumulative distributions received exceed the cumulative equity earnings recognized by CQP, in which the excess distributions received are deemed returns of investment and classified as cash inflows from investing activities.

A substantial amount of CQP's operating, investing and financing activities are conducted by its subsidiaries. The Condensed Financial Statements should be read in conjunction with CQP's Consolidated Financial Statements.

NOTE 2—DEBT

Our debt consisted of the following (in millions):

	December 31,	
	2023	2022
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	1,400	—
Total senior notes	5,600	4,200
Credit facilities	—	—
Revolving credit and guaranty agreement	—	—
Total debt	5,600	4,200
Unamortized debt issuance costs	(58)	(41)
Total long-term debt, net of debt issuance costs	$ 5,542	$ 4,159

All of our future principal payments that we are obligated to make on our outstanding debt at December 31, 2023 are due 2029 and thereafter.

NOTE 3—SUPPLEMENTAL CASH FLOW INFORMATION

The following table provides supplemental disclosure of cash flow information, excluding any non-cash contributions from affiliates of Cheniere to our subsidiaries for which the contribution passed through us (in millions):

	Year Ended December 31,		
	2023	2022	2021
Cash paid during the period for interest, net of amounts capitalized	$ 168	$ 163	$ 197
Cash distributions from subsidiaries	2,838	3,282	2,349

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 PARTNERS, L.P.

By: Cheniere Energy Partners GP, LLC,
its general partner

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 general partner 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, Chairman of the Board (Principal Executive Officer)	February 21, 2024
/s/ Zach Davis Zach Davis	Executive Vice President and Chief Financial Officer, Director (Principal Financial Officer)	February 21, 2024
/s/ David Slack David Slack	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 21, 2024
/s/ Corey Grindal Corey Grindal	Executive Vice President and Chief Operating Officer, Director	February 21, 2024
/s/ Taylor Johnson Taylor Johnson	Deputy General Counsel, Director	February 21, 2024
/s/ Brian Baker Brian Baker	Director	February 21, 2024
/s/ James R. Ball James R. Ball	Director	February 21, 2024
/s/ Christopher Dell'Amore Christopher Dell'Amore	Director	February 21, 2024
/s/ Lon McCain Lon McCain	Director	February 21, 2024
/s/ Vincent Pagano Jr. Vincent Pagano Jr.	Director	February 21, 2024
/s/ Scott Peak Scott Peak	Director	February 21, 2024
/s/ Oliver G. Richard, III Oliver G. Richard, III	Director	February 21, 2024