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, 2022

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.)

700 Milam Street, Suite 1900
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**	**NYSE American**

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, 2022.

As of February 17, 2023, the registrant had 484,033,123 common units outstanding.

Documents incorporated by reference: **None**

CHENIERE ENERGY PARTNERS, L.P.

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DEFINITIONS

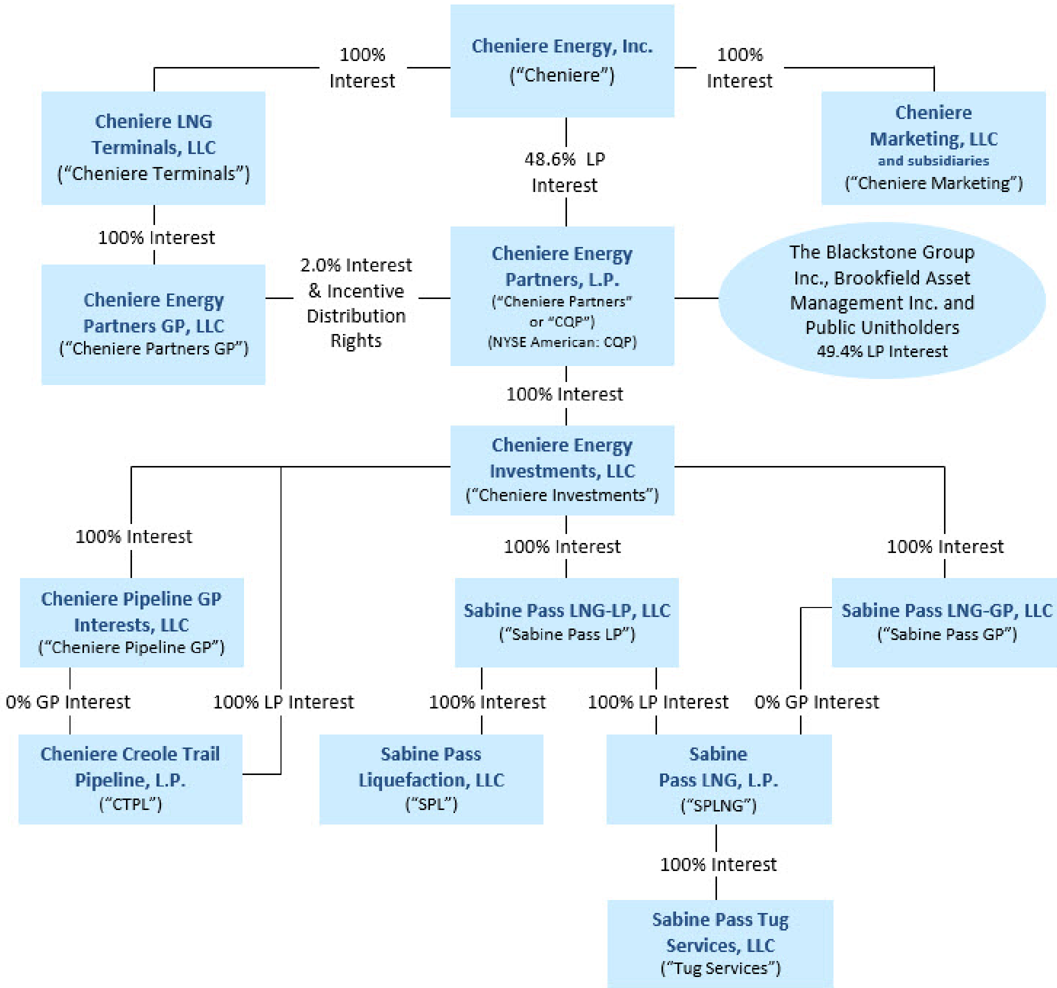
As used in this annual report, the terms listed below have the following meanings:

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
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
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 USD 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 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
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, 2022, 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, including SPLNG, SPL and CTPL.

CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING STATEMENTS

This annual report contains certain statements that are, or may be deemed to be, “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical or present facts or conditions, included herein or incorporated herein by reference are “forward-looking statements.” Included among “forward-looking statements” are, among other things:

- statements 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 and other industrial uses. 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, with Train 6 having achieved substantial completion on February 4, 2022, for a total operational production capacity of approximately 30 mtpa of LNG (the "Liquefaction Project"). The Sabine Pass LNG Terminal also has three marine berths, with the third berth having achieved substantial completion on October 27, 2022, 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, and operational regasification facilities that include five LNG storage tanks with aggregate capacity of approximately 17 Bcfe and vaporizers with total regasification capacity of approximately 4 Bcf/d. We also own a 94-mile pipeline through our subsidiary, CTPL, that interconnects our facilities to several large 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 index price, less a fixed liquefaction fee, shipping and other costs. Through our SPAs and IPM agreement, we have contracted approximately 85% of the total production capacity from the Liquefaction Project with approximately 15 years of weighted average remaining life as of December 31, 2022. For further discussion of the contracted future cash flows under our revenue arrangements, see Liquidity and Capital Resources in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

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 hold a significant land position at the Sabine Pass LNG Terminal, which provides opportunity for further liquefaction capacity expansion. The development of this site 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 final investment decision.

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 eight of eleven third party long-term SPA customers as of December 31, 2022;
- 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 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.

Liquefaction Facilities

The Liquefaction Project, as described above under the caption General, is one of the largest LNG production facilities in the world with six Trains and three marine berths.

The following summarizes the volumes of natural gas for which we have received approvals from FERC to site, construct and operate 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 Sabine Pass LNG Terminal through long-term natural gas supply agreements, including an IPM agreement. Additionally, to ensure that SPL is able to transport natural gas feedstock to the Sabine Pass LNG Terminal and manage inventory levels, it has entered into firm pipeline transportation and storage contracts with third parties.

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 they have reserved. Prior to its cancellation effective December 31, 2022, SPLNG also had a TUA for 1 Bcf/d with Chevron. Approximately 2 Bcf/d of the remaining capacity has been reserved under a TUA by SPL. SPL also has a partial TUA assignment agreement with TotalEnergies, as further described in Note 13—Revenues of our Notes to Consolidated Financial Statements.

Customers

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.

The following table shows customers with revenues of 10% or greater of total revenues from external customers:

	Percentage of Total Revenues from External Customers		
	Year Ended December 31,		
	2022	**2021**	**2020**
BG Gulf Coast LNG, LLC and affiliates	22%	24%	24%
GAIL (India) Limited	15%	17%	18%
Korea Gas Corporation	15%	17%	17%
Naturgy LNG GOM, Limited	15%	16%	15%
TotalEnergies Gas & Power North America, Inc.	10%	11%	11%

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

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 FERC uses to evaluate applications to include, among other things, reasonably foreseeable greenhouse gas emissions that may be attributable to the project and the project's impact on environmental justice communities. On March 24, 2022, the FERC pulled back 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.

The FERC issued its final Order Granting Section 3 Authority ("Order") in April 2012 approving our application for an order under Section 3 of the NGA authorizing the siting, construction and operation of Trains 1 through 4 of the Liquefaction Project (and related facilities). Subsequently, in May 2012, the FERC issued written approval to commence site preparation work for Trains 1 through 4. In October 2012, we applied to amend the FERC approval to reflect certain modifications to the Liquefaction Project, and in August 2013, the FERC issued an Order approving the modifications. In October 2013, we applied to further amend the FERC approval, requesting authorization to increase the total permitted LNG production capacity of Trains 1 through 4 from the then authorized 803 Bcf/yr to 1,006 Bcf/yr so as to more accurately reflect the estimated maximum LNG production capacity of Trains 1 through 4. In February 2014, the FERC issued an order approving the October 2013 application (the "February 2014 Order"). A party to the proceeding requested a rehearing of the February 2014 Order, and in September 2014, the FERC issued an order denying the rehearing request (the "FERC Order Denying Rehearing"). The party petitioned the U.S. Court of Appeals for the District of Columbia Circuit (the "Court of Appeals") to review the February 2014 Order and the FERC Order Denying Rehearing. The court denied the petition in June 2016. In September 2013, we filed an application with the FERC for authorization to add Trains 5 and 6 to the Liquefaction Project, which was granted by the FERC in an Order issued in April 2015 and an Order denying rehearing issued in June 2015. These Orders are not subject to appellate court review. In October of 2018, SPL applied to the FERC for authorization to add a third marine berth to the Liquefaction Project, which FERC approved in February of 2020. FERC issued written approval to commence site preparation work for the third berth in June 2020.

The Creole Trail Pipeline, which interconnects with the Sabine Pass LNG Terminal, holds a certificate of public convenience and necessity from the FERC under Section 7 of the NGA. The FERC's approval under Section 7 of the NGA, as well as several other material governmental and regulatory approvals and permits, is required prior to making any modifications to the Creole Trail Pipeline as it is a regulated, interstate natural gas pipeline. In February 2013, the FERC approved CTPL's application for authorization to construct, own, operate and maintain certain new facilities in order to enable bi-directional natural gas flow on the Creole Trail Pipeline system to allow for the delivery of up to 1,530,000 Dekatherms per day of feed gas to the Sabine Pass LNG Terminal. In November 2013, CTPL received approval from the Louisiana Department of Environmental Quality ("LDEQ") for the proposed modifications and construction was completed in 2015. In September 2013, as part of the Application for Trains 5 and 6, we filed an application with the FERC for authorization to construct and operate an extension and expansion of Creole Trail Pipeline and related facilities in order to deliver additional domestic natural gas supplies to the Sabine Pass LNG Terminal, which was granted by the FERC in an order issued in April 2015 and an order denying rehearing issued in June 2015. These orders are not subject to appellate court review.

On September 27, 2019, SPL filed a request with the FERC pursuant to Section 3 of the NGA, requesting authorization to increase the total LNG production capacity of the terminal from currently authorized levels to an amount which reflects more accurately the capacity of the facility based on enhancements during the engineering, design and construction process, as well as operational experience to date. The requested authorizations do not involve construction of new facilities. Corresponding applications for authorization to export the incremental volumes were also submitted to the DOE. The DOE issued Orders granting authorization to export LNG to FTA countries in April 2020 and to non-FTA countries in March 2022. In October 2021, the FERC issued its Orders Amending Authorization under Section 3 of the NGA. In March 2022, the DOE authorized the export of an additional 152.64 Bcf/yr of domestically produced LNG by vessel from the Sabine Pass LNG Terminal through December 31, 2050 to non-FTA countries, that were previously authorized for FTA countries only.

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 material governmental and regulatory approvals and permits are required throughout the life of our 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 our LNG terminal and Creole Trail Pipeline. For example, throughout the life of our 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 have 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*Liquefaction Facilities.* Although it is not expected to occur, the loss of an export authorization could be a force majeure event under our SPAs.

Under Section 3 of the NGA applications for exports of natural gas to FTA countries, which allow for national treatment for trade in natural gas, are "deemed to be consistent with the public interest" and shall be granted by the DOE without "modification or delay." FTA countries currently recognized by the DOE for exports of LNG include Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea and Singapore. FTAs with Israel and Costa Rica do not require national treatment for trade in natural gas. Applications for export of LNG to non-FTA countries are considered by the DOE in a notice and comment proceeding whereby the public and other interveners are provided the opportunity to comment and may assert that such authorization would not be consistent with the public interest.

Pipeline and Hazardous Materials Safety Administration

Our 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 $258,000 per day per violation, with a maximum administrative civil penalty of approximately $2.6 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 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 (the "Title V Permit") and the Prevention of Significant Deterioration Permit (the "PSD 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 recent 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. We do not believe, however, that our operations, or the construction and operations of our liquefaction facilities, will be materially and adversely affected by any such requirements.

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. 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.

We are supportive of regulations reducing greenhouse gas ("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. The EPA has proposed additional new regulations to reduce methane emissions from both new and existing sources within the Crude Oil and Natural Gas source category that impact our assets and our supply chain.

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 threshold for facilities that report their GHG emissions under the EPA's Greenhouse Gas Emissions Reporting Program ("GHGRP") Part 98 ("Subpart W") 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. At this time, we do not expect it 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 and in Texas by the General Land Office). This program is implemented to ensure that impacts to coastal areas are consistent with the intent of the CZMA to manage the coastal areas.

Clean Water Act

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 operation 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 that our operations, or the construction and operations of the Sabine Pass LNG Terminal, will be materially and adversely affected by such regulatory actions.

Market Factors and Competition

Market Factors

Our ability to enter into additional long-term SPAs to underpin the development of additional Trains, sale of LNG by Cheniere Marketing or development of 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 renewable 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 80 mtpa of import capacity over the near-term to secure access to LNG and displace Russian gas imports. In India, there are nearly 12,000 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 decrease harmful emissions.

As a result of these dynamics, we expect gas and LNG to continue to play an important role in satisfying energy demand going forward. In its fourth quarter 2022 forecast, Wood Mackenzie Limited ("WoodMac") forecasts that global demand for LNG will increase by approximately 53%, from 388.5 mtpa, or 18.6 Tcf, in 2021, to 595.7 mtpa, or 28.6 Tcf, in 2030 and to 677.8 mtpa or 32.5 Tcf in 2040. In its fourth quarter 2022 forecast, WoodMac also forecasts LNG production from existing operational facilities and new facilities already under construction will be able to supply the market with approximately 537 mtpa in 2030, declining to 490 mtpa in 2040. This could result in a market need for construction of an additional approximately 59 mtpa of LNG production by 2030 and about 187 mtpa by 2040. As a cleaner burning fuel with lower emissions than coal or liquid fuels in power generation, we expect gas and LNG to play a central role in balancing grids and contributing to a low carbon energy system globally. We believe the capital and operating costs of the uncommitted capacity of our Liquefaction Project is competitive with new proposed projects globally and we are well-positioned to capture a portion of this incremental market need.

Our LNG terminal business has 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. 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 production capacity from the Liquefaction Project, with approximately 15 years of weighted average remaining life as of December 31, 2022, which includes volumes contracted under SPAs in which the 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

When SPL needs to replace 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 under the Cheniere Marketing SPA, 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 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 2022, Cheniere published *Acting Now, Securing Tomorrow*, its third Corporate Responsibility ("CR") report, which outlines Cheniere's focus on sustainability and its performance on key environmental, social and governance ("ESG") metrics. 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, we are collaborating with natural gas midstream companies, methane detection technology providers and/or leading academic institutions on quantification, monitoring, reporting and verification ("QMRV") of GHG research and development projects, co-founding and sponsoring multidisciplinary research and education initiatives led by the University of Texas at Austin in collaboration with Colorado State University and the Colorado School of Mines.

Cheniere also 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 in October 2022.

Our total expenditures related to the climate initiatives, including capital expenditures, were not material to our Consolidated Financial Statements during the years ended December 31, 2022, 2021 and 2020. However, as 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 initiatives to evolve accordingly. While we have not incurred material direct capital expenditures related to climate change, we aspire to conduct our business in a safe and responsible manner and are proactive in our management of environmental impacts, risks and opportunities. We face certain business and operational risks associated with physical impacts from climate change, such as potential increases in 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, operation and maintenance of the Sabine Pass LNG Terminal and the Liquefaction Project 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, 2022, Cheniere and its subsidiaries had 1,551 full-time employees, including 517 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.

Available Information

Our common units have been publicly traded since March 21, 2007 and are traded on the NYSE American under the symbol "CQP." Our principal executive offices are located at 700 Milam Street, Suite 1900, 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, 700 Milam Street, Suite 1900, 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 could affect our financial performance or could cause actual results to differ materially from estimates or expectations contained in our forward-looking statements. We may encounter risks in addition to those described below. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, may also impair or 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

Our existing level of cash resources and significant debt 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, 2022, we had $904 million of cash and cash equivalents, $92 million of restricted cash and cash equivalents, a total of $1.6 billion of available commitments under our credit facilities and $16.3 billion of total debt outstanding on a consolidated basis (before unamortized premium, 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. Our ability to 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 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, 2022, we had SPAs with 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 and limit the indebtedness that our subsidiaries can incur. For example, 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 debt service coverage ratio of 1.25:1.00 is satisfied.

Our subsidiaries' inability to pay distributions to us or to incur additional indebtedness 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 agreement, could adversely affect our earnings reported under GAAP and affect 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, other than certain derivatives for which we have elected to apply accrual accounting, 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. 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 includes $1.1 billion of losses resulting from changes in 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.

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, 2022 and 2021, we had collateral posted with counterparties by us of $35 million and $7 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 their 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 transport 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 imports from North America; and
- cyclical trends in general business and economic conditions that cause changes in the demand for natural gas.

Adverse trends or developments affecting any of these factors could result in decreases in the price of LNG and/or natural gas, which could materially and adversely affect 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 North America and delivered to international markets at a lower cost than the cost of alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas may be discovered outside the 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 agreements approximately 85% of the total production capacity from the Liquefaction Project with approximately 15 years of weighted average remaining life as of December 31, 2022. 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 the outbreak of 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 the Delta and Omicron variants, has had no adverse impact on our on-going operations, the risk of future variants 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 us.

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

To date, the FERC has issued orders under Section 3 of the NGA authorizing the siting, construction and operation of the six Trains and related facilities of the Liquefaction Project, as well as orders under Section 7 of the NGA authorizing the construction and operation of the Creole Trail Pipeline. To date, the DOE has also issued orders under Section 4 of the NGA authorizing SPL to export domestically produced LNG. 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. We are currently in compliance with such conditions; however, failure to comply or our inability to obtain and maintain existing or newly imposed approvals and permits, filings, which 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 the siting of LNG facilities due to safety, environmental or security concerns, 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 $1.4 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 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 or maintaining permits from regulatory agencies or to 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. 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 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. 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, 2022 and 2021. Revised, reinterpreted or additional laws and regulations 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.

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. Although no fines or penalties have been imposed on us to date, 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 $2.6 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, 2022, Cheniere and its subsidiaries had 1,551 full-time employees, including 517 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, or other 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. 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 future Trains.

We expect that there will be additional agreements or arrangements with Cheniere and its affiliates, including future interconnection, natural gas balancing and storage agreements with one or more Cheniere-affiliated natural gas pipelines, services agreements, as well as 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, 2022, Cheniere owned 239,872,502 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 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. The determination of cumulative net income is complex and unclear in certain respects, and 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. The Treasury regulations further provide that these rules will generally not apply to 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 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 self-reported deviations arising from operation of the Sabine Pass LNG Terminal and the commissioning of the Liquefaction Project, and relating to certain requirements under its Title V Permit. The matter involves deviations self-reported to LDEQ pursuant to the Title V Permit and covering the time period from January 1, 2012 through March 25, 2016. On April 11, 2016, certain of our subsidiaries received a Consolidated Compliance Order and Notice of Potential Penalty (the “Compliance Order”) from LDEQ covering deviations self-reported during that time period. Certain of our subsidiaries continue to work with LDEQ to resolve the matters identified in the Compliance Order. We do not expect that any ultimate sanction will have a material adverse impact on our financial results.

PHMSA Matter

In February 2018, the PHMSA issued a Corrective Action Order (the “CAO”) to SPL in connection with a minor LNG leak from one tank and minor vapor release from a second tank at the Sabine Pass LNG Terminal (the “2018 SPL tank incident”). These two tanks have been taken out of operational service while we conduct analysis, repair and remediation. On April 20, 2018, SPL and PHMSA executed a Consent Agreement and Order (the “Consent Order”) that replaces and supersedes the CAO. On July 9, 2019, PHMSA and FERC issued a joint letter setting out operating conditions required to be met prior to SPL returning the tanks to service. In July 2021, PHMSA issued a Notice of Probable Violation (“NOPV”) and Proposed Civil Penalty to SPL alleging violations of federal pipeline safety regulations relating to the 2018 SPL tank incident and proposing civil penalties totaling $2,214,900. On September 16, 2021, PHMSA issued an Amended NOPV that reduced the proposed penalty to $1,458,200. On October 12, 2021, SPL responded to the Amended NOPV, electing not to contest the alleged violations in the Amended NOPV and electing to pay the proposed reduced penalty. PHMSA notified SPL in a letter dated November 9, 2021 that the case was considered “closed.” SPL continues to coordinate with PHMSA and FERC to address the matters relating to the 2018 SPL tank incident, including repair approach and related analysis. One tank has been placed back into operational service. We do not expect that the Consent Order and related analysis, repair and remediation or resolution of the NOPV will have a material adverse impact on our financial results or operations.

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 began trading on the NYSE American under the symbol "CQP" commencing with our initial public offering on March 21, 2007. As of February 17, 2023, we had 484.0 million common units outstanding held by 9 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. The 2019 CQP Credit Facilities described in Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations may also limit our ability to make distributions.

Upon the closing of our initial public offering, Cheniere received 135.4 million subordinated units. In July 2020, the board of directors of our general partner confirmed and approved that, following the distribution with respect to the three months ended June 30, 2020, the financial tests required for conversion of our subordinated units had been met under the terms of the partnership agreement. Accordingly, effective August 17, 2020, the first business day following the payment of the distribution, all of our subordinated units were automatically converted into common units on a one-for-one basis and the subordination period was terminated.

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 2020 items and variance drivers between the year ended December 31, 2021 as compared to December 31, 2020 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, 2021.

Our discussion and analysis includes the following subjects:

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 located at Sabine Pass, Louisiana (the "Sabine Pass LNG Terminal") with six operational Trains. In addition to natural gas liquefaction facilities at the Sabine Pass LNG Terminal (the "Liquefaction Project"), the Sabine Pass LNG Terminal also has operational regasification facilities and a pipeline that interconnects the Sabine Pass LNG Terminal with a number of large interstate and intrastate pipelines. 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. We contract 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 index price, less a fixed liquefaction fee, shipping and other costs. Through our SPAs and IPM agreement, we have contracted approximately 85% of the total production capacity from the Liquefaction Project with approximately 15 years of weighted average remaining life as of December 31, 2022. 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 business in the future.

Overview of Significant Events

Our significant events since January 1, 2022 and through the filing date of this Form 10-K include the following:

Strategic

- In February 2023, certain of our subsidiaries initiated the pre-filing review process with the FERC under the National Environmental Policy Act for an expansion adjacent to the Liquefaction Project consisting of up to three Trains with an expected total production capacity of approximately 20 mtpa of LNG.
- In November 2022, SPL and Cheniere Marketing entered into an SPA for approximately 0.85 mtpa of LNG associated with the IPM agreement between SPL and Tourmaline Oil Marketing Corp., a subsidiary of Tourmaline Oil Corp (as supplier) ("Tourmaline"), discussed below.

- On September 23, 2022, Corey Grindal, Executive Vice President, Worldwide Trading and Tim Wyatt, Senior Vice President, Corporate Development and Strategy, were appointed to the Board of Directors of Cheniere Energy Partners GP, LLC ("Cheniere GP"). Mr. Grindal was also promoted to Executive Vice President and Chief Operating Officer of Cheniere GP, effective January 2, 2023.
- In June 2022, SPL entered into an SPA with Chevron U.S.A. Inc. ("Chevron") to sell Chevron approximately 1.0 mtpa of LNG between 2026 and 2042.
- 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 ("TMSA") between the parties and their affiliates (the "Termination Agreement"), effective July 6, 2022, for a lump sum fee of $765 million.
- In February 2022, in connection with a prior commitment from Cheniere to collateralize financing for Train 6 of the Liquefaction Project:
    - Cheniere Marketing entered into agreements to novate to SPL certain SPAs entered into with ENN LNG (Singapore) Pte Ltd. and a subsidiary of Glencore plc, with effective dates of January 1, 2023 and February 17, 2022, respectively, aggregating approximately 21 million tonnes of LNG to be delivered between 2023 and 2035.
    - The board of directors of Cheniere Partners GP approved the entry by SPL into (1) an agreement to novate to SPL an IPM agreement between Corpus Christi Liquefaction Stage III, LLC ("CCL Stage III"), formerly a wholly owned direct subsidiary of Cheniere (as purchaser) that merged with and into Corpus Christi Liquefaction, LLC, and Tourmaline to purchase 140,000 MMBtu per day of natural gas at a price based on Platts Japan Korea Marker ("JKM"), for a term of approximately 15 years beginning in early 2023 (the "Tourmaline IPM") and (2) a FOB SPA with Cheniere Marketing International LLP to sell LNG associated with the natural gas to be supplied under the IPM agreement. The agreement to assign the Tourmaline IPM agreement from CCL Stage III to SPL was executed and the assignment was effective on March 15, 2022.

Operational

- As of February 17, 2023, approximately 1,990 cumulative LNG cargoes totaling over 135 million tonnes of LNG have been produced, loaded and exported from the Liquefaction Project.
- On October 27, 2022, substantial completion of the third berth at the Sabine Pass LNG Terminal was achieved.
- On February 4, 2022, substantial completion of Train 6 of the Liquefaction Project was achieved (the "Train 6 Completion").

Financial

- In December and November 2022, SPL issued an aggregate principal amount of $70 million of 6.293% Senior Secured Notes due 2037 (the "6.293% SPL Senior Notes") and $430 million of 5.900% Senior Secured Amortizing Notes due 2037 (the "5.900% SPL Senior Notes"), respectively, with a weighted average life of approximately 9.6 years and 9.5 years, respectively. The proceeds from the 6.293% SPL Senior Notes and the 5.900% SPL Senior Notes, together with cash on hand, were used to redeem the remaining outstanding amount of SPL's $1.5 billion aggregate principal amount of Senior Secured Notes due 2023 (the "2023 SPL Senior Notes"), subsequent to the $300 million redemption in October 2022.
- In September 2022, Moody's Corporation ("Moody's") upgraded its issuer credit ratings of CQP and SPL from Ba2 and Baa3, respectively, to Ba1 and Baa2, respectively, with a stable outlook. Additionally in September 2022, Fitch Ratings upgraded its issuer credit ratings of CQP and SPL from BB+ and BBB-, respectively, to BBB- and BBB, respectively, both investment grade credit ratings, with a stable outlook. In November 2022, CQP achieved its second issuer investment grade credit rating from S&P Global Ratings ("S&P"), as a result of an upgrade from BB+ to BBB, with a stable outlook, which resulted in the release of previous required collateral on CQP's revolving credit facility, changing the status of the facility to unsecured. In February 2023, S&P also upgraded its issuer credit ratings of SPL from BBB to BBB+ with stable outlook.
- We declared aggregate distributions of $4.25 per common unit during the year ended December 31, 2022. On January 27, 2023, we declared a cash distribution of $1.07 per common unit to unitholders of record as of

February 6, 2023 and the related general partner distribution that was paid on February 14, 2023. These distributions consist of a base amount of $0.775 per unit and a variable amount of $0.295 per unit.

- In February 2022, we announced the initiation of quarterly distributions to be comprised of a base amount plus a variable amount, which began with the distribution related to the first quarter of 2022. The variable amount takes into consideration, among other things, amounts reserved for annual debt repayment and capital allocation goals, anticipated capital expenditures to be funded with cash and cash reserves to provide for the proper conduct of the business.

Market Environment

The LNG market in 2022 saw unprecedented price volatility across all natural gas and LNG benchmarks. Gas market fundamentals across the globe were tight and exacerbated by the Russia / Ukraine war risks, and later by the drastic reduction in Russian natural gas flows to the European Union ("EU"). Concerns over low natural gas and LNG inventories and low additional LNG supply availability early in the year were intensified by the war dynamics in Europe and by further constraints on natural gas and LNG supplies caused by the outage at the Freeport LNG facility in June and the explosion on the Nordstream 1 and Nordstream 2 Pipelines in September. Several EU policy initiatives were passed to ensure underground gas storage in the region was filled before winter. Europe had to compete for LNG cargoes resulting in unprecedented price spikes. These conditions were worsened by high coal prices, low nuclear generation output and low hydro levels in Europe, which limited optionality for power generators and deepened the energy crisis in Europe.

Despite the generally tight supply conditions, according to Kpler, global LNG demand grew by approximately 5% from 2021, adding an additional 19.5 million tonnes to the overall market. LNG imports into Europe and Turkey, increased by 45.9 million tonnes, or 61% year-over-year in 2022. This growth was primarily accompanied by a pronounced slowdown in economic activity in China, which contributed to a 7% decrease in Asia's LNG demand of 19.1 million tonnes from 2021. These sizeable EU LNG requirements resulting from the war fallout and the increase in global demand, especially demand for increased imports to Europe and Turkey, exposed the vulnerability of the LNG industry in terms of supply constraints and under-investments. This was manifested in the price levels and the magnitude of the price spreads between the benchmarks. As an example, the Dutch Title Transfer Facility ("TTF") monthly settlement prices averaged $40.9/MMBtu in 2022, approximately 184% higher than the $14.4/MMBtu average in 2021, and the TTF monthly settlement prices averaged $42.3/MMBtu in the fourth quarter of 2022, approximately 46% higher than the $28.9/MMBtu average in the fourth quarter of 2021. Similarly, the 2022 average settlement price for the JKM increased 128% year-over-year to an average of $34.2/MMBtu in 2022, and the fourth quarter of 2022 average settlement price for the JKM increased 38% year-over-year to an average of $38.5/MMBtu. This extreme price increase triggered a strong supply response from the U.S., which played a significant role in balancing the global LNG market. Despite the outage at Freeport LNG, the U.S. exported approximately 77 million tonnes of LNG in 2022, a gain of approximately 9% from 2021, as the market continued to pull on supplies from our facilities and those of our competitors. Exports from our Liquefaction Project reached 29.1 million tonnes, representing over 70% of the gain in the U.S. total for the year.

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 war on our supply chain. Consequently, we believe we are well positioned to help meet the needs of our international LNG customers to overcome their supply shortages.

Results of Operations

(in millions, except per unit data)	Year Ended December 31, 2022	2021	Variance
Revenues			
LNG revenues	$ 11,507	$ 7,639	$ 3,868
LNG revenues—affiliate	4,568	1,472	3,096
LNG revenues—related party	—	1	(1)
Regasification revenues	1,068	269	799
Other revenues	63	53	10
Total revenues	17,206	9,434	7,772
Operating costs and expenses			
Cost of sales (excluding items shown separately below)	11,887	5,290	6,597
Cost of sales—affiliate	213	84	129
Cost of sales—related party	—	17	(17)
Operating and maintenance expense	757	635	122
Operating and maintenance expense—affiliate	166	142	24
Operating and maintenance expense—related party	72	46	26
General and administrative expense	5	9	(4)
General and administrative expense—affiliate	92	85	7
Depreciation and amortization expense	634	557	77
Other	—	11	(11)
Other—affiliate	—	1	(1)
Total operating costs and expenses	13,826	6,877	6,949
Income from operations	3,380	2,557	823
Other income (expense)			
Interest expense, net of capitalized interest	(870)	(831)	(39)
Loss on modification or extinguishment of debt	(33)	(101)	68
Other income, net	21	3	18
Other income—affiliate	—	2	(2)
Total other expense	(882)	(927)	45
Net income	$ 2,498	$ 1,630	$ 868
Basic and diluted net income per common unit	$ 3.27	$ 3.00	$ 0.27

Operational volumes loaded and recognized from the Liquefaction Project

	Year Ended December 31, 2022	2021	Variance
LNG volumes loaded and recognized as revenues (in TBtu) (1)	1,520	1,288	232

(1) The year ended December 31, 2021 includes eight TBtu that were loaded at our affiliate's facility.

Net income. The $868 million increase in net income for the year ended December 31, 2022 as compared to the same period of 2021 was primarily attributable to:

- increased LNG revenues, net of cost of sales and excluding the effect of derivative losses (as further described below), of $1.4 billion, approximately half of which was attributable to higher margins on sales indexed to Henry Hub, with variable consideration on our long-term SPAs generally priced at 115% of Henry Hub, and half of which was attributable to increased volume delivered between the comparable periods, in part due to the Train 6 Completion; and
- additional income resulting from the lump sum fee from Chevron of $765 million related to the Termination Agreement, as discussed in Overview of Significant Events;

These favorable variance drivers were partially offset by:

- an unfavorable variance of $1.2 billion in derivative losses from changes in fair value in the year ended December 31, 2022 as compared to the same period of 2021. During the year ended December 31, 2022 we incurred losses of $757 million on the derivative liability associated with the Tourmaline IPM agreement following its assignment to SPL from CCL Stage III in March 2022. See Overview of Significant Events for further discussion of the assignment. The associated losses following the assignment were 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 unfavorable shifts in the international forward commodity curve.

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

Revenues. $7.8 billion increase between comparable periods primarily attributable to:

- $5.2 billion increase due to higher pricing per MMBtu, from increased Henry Hub pricing;
- $1.8 billion increase due to higher volumes of LNG delivered between the periods, which increased 38 TBtu or 5%, as result of the additional production capacity of approximately 5 mtpa arising from the Train 6 Completion; and
- $799 million increase in regasification revenues, due to the acceleration of regasification revenues from the Termination Agreement with Chevron, as described above in Overview of Significant Events.

Operating costs and expenses. $6.9 billion increase between comparable periods primarily attributable to:

- $5.5 billion increase in cost of sales excluding the effect of derivative losses described below, primarily as a result of $5.4 billion in increased cost of natural gas feedstock largely due to higher U.S. natural gas prices and, to a lesser extent, from increased volume of natural gas liquified and delivered as LNG, as discussed above under the caption *Revenues*; and
- $1.2 billion unfavorable variance in derivative losses from changes in fair value and settlements included in cost of sales, from $32 million derivative gain in the year ended December 31, 2021 to $1.2 billion derivative loss in the year ended December 31, 2022, primarily due to non-cash unfavorable changes in fair value of our commodity derivatives that are attributed to positions indexed to international gas prices, specifically associated with the Tourmaline IPM agreement that was assigned to us as discussed in *Net income* above.

Other income (expense). $45 million decrease in total other expense between comparable periods primarily attributable to:

- $68 million decrease in loss on modification or extinguishment of debt, primarily due to a reduction in premiums paid for the early redemption or repayment of debt principal, as further described under *Financing Cash Flows* in Sources and Uses of Cash within Liquidity and Capital Resources, partially offset by a $31 million loss associated with a premium paid to Chevron to terminate a revenue sharing agreement between the parties; partially offset by
- $39 million increase in interest expense, net of capitalized interest, as a result of a result of a lower portion of total interest costs eligible for capitalization following the Train 6 Completion, which was partially offset by lower interest cost as a result of reduced outstanding debt between the periods.

Significant factors affecting our results of operations

In addition to sources and uses of liquidity as discussed in Liquidity and Capital Resources, below are additional 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 agreement assigned to us during the year ended December 31, 2022 as described further in Overview of Significant Events, 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. Because 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, 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 our control, notwithstanding the operational intent to mitigate risk exposure over time.

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 years ended December 31, 2022 and 2021, we realized offsets to LNG terminal costs of $148 million and $105 million, respectively, corresponding to 13 TBtu and 12 TBtu, respectively, that were related to the sale of commissioning cargoes from Train 6 of the Liquefaction Project.

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. In the long term, we expect to meet our cash requirements 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, 2022
Cash and cash equivalents	$ 904
Restricted cash and cash equivalents designated for the Liquefaction Project	92
Available commitments under our credit facilities (1):	
SPL’s Working capital revolving credit and letter of credit reimbursement agreement	872
CQP’s credit facilities	750
Total available commitments under our credit facilities	1,622
Total available liquidity	$ 2,618

(1) Available commitments represent total commitments less loans outstanding and letters of credit issued under each of our credit facilities as of December 31, 2022. 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, 2022 will be driven by future sources of liquidity and future cash requirements as further discussed below 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 expenses are managed by subsidiaries of Cheniere under affiliate agreements, which may require SPL to advance cash to the respective affiliates, however the cash remains restricted to CQP for operation and construction of the Liquefaction Project; 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.

Notwithstanding 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 $1.5 billion of 4.500% Senior Notes due 2029, $1.5 billion of 4.000% Senior Notes due 2031 (the “2031 CQP Senior Notes”) and $1.2 billion of 3.25% Senior Notes due 2032 (collectively, 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 its guarantee obligations 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 the any claims by the Non-Guarantors' creditors, including trade creditors.

Summarized Balance Sheets (in millions)	**December 31,**	
	2022	**2021**
ASSETS		
Current assets		
Cash and cash equivalents	$ 904	$ 876
Accounts receivable from Non-Guarantors	55	49
Other current assets	40	53
Current assets—affiliate	171	137
Current assets with Non-Guarantors	—	1
Total current assets	1,170	1,116
Property, plant and equipment, net of accumulated depreciation	2,946	2,422
Other non-current assets, net	109	119
Total assets	$ 4,225	$ 3,657
LIABILITIES		
Current liabilities		
Due to affiliates	$ 193	$ 167
Deferred revenue from Non-Guarantors	24	22
Other current liabilities	95	95
Other current liabilities from Non-Guarantors	2	—
Total current liabilities	314	284
Long-term debt, net of premium, discount and debt issuance costs	4,159	4,154
Finance lease liabilities	18	—
Other non-current liabilities	78	87
Non-current liabilities—affiliate	18	15
Total liabilities	$ 4,587	$ 4,540

Summarized Statement of Income (in millions)	**Year Ended December 31, 2022**
Revenues	$ 1,132
Revenues from Non-Guarantors	544
Total revenues	1,676
Operating costs and expenses	208
Operating costs and expenses—affiliate	203
Total operating costs and expenses	411
Income from operations	1,265
Net income	1,045

Future Sources and Uses of Liquidity

Future Sources of Liquidity under Executed Contracts

Because many of our sales contracts have long-term durations, we are contractually entitled to significant future consideration under our SPAs and TUAs 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, 2022. 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 contracts as of December 31, 2022 (in billions):

	Estimated Revenues Under Executed Contracts by Period (1)			
	2023	**2024 - 2027**	**Thereafter**	**Total**
LNG revenues (fixed fees) (2)	$ 3.7	$ 14.7	$ 34.4	$ 52.8
LNG revenues (variable fees) (2) (3)	8.1	30.6	69.9	108.6
Regasification revenues	0.1	0.5	0.2	0.8
Total	$ 11.9	$ 45.8	$ 104.5	$ 162.2

(1) Agreements in force as of December 31, 2022 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2022. The timing of revenue recognition under GAAP may not align with cash receipts, although we do not consider the timing difference to be material. The estimates above reflect management's assumptions and currently known market conditions and other factors as of December 31, 2022. 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.

(2) LNG revenues (including $2.0 billion and $12.9 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 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, 2022. The pricing structure 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. 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 to the extent the consideration is considered constrained due to the uncertainty of ultimate pricing and receipt.

LNG Revenues

Through our SPAs and IPM agreement, we have contracted approximately 85% of the total production capacity from the Liquefaction Project, with approximately 15 years of weighted average remaining life as of December 31, 2022. 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 a free on board ("FOB") basis 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 and variable transportation and liquefaction fuel 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 for the Liquefaction Project. Our long-term SPA customers consist of creditworthy counterparties, with an average credit rating of A, A2 and A by S&P, Moody's and Fitch, respectively. A discussion of revenues under our SPAs can be found in Note 13—Revenues of our Notes to Consolidated Financial Statements.

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.

Regasification Revenues

SPLNG has a long-term, third party TUA with TotalEnergies Gas & Power North America, Inc. ("TotalEnergies"), under which TotalEnergies is required to pay fixed monthly fees, whether or not it uses the approximately 1 Bcf/d of the regasification capacity it has reserved at the Sabine Pass LNG Terminal. TotalEnergies is obligated to make monthly capacity payments to SPLNG aggregating approximately $125 million annually, prior to inflation adjustments, for 20 years that commenced in 2009. Total S.A. has guaranteed TotalEnergies' obligations under its TUA up to $2.5 billion, subject to certain exceptions.

SPLNG has also entered into a TUA with SPL to reserve approximately 2 Bcf/d of the regasification capacity at the Sabine Pass LNG Terminal. SPL is obligated to make monthly capacity payments to SPLNG aggregating approximately $250 million annually, prior to inflation adjustments, continuing until at least May 2036. SPL entered into 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 that started in 2019. 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. Payments made by SPL to TotalEnergies under this partial TUA assignment agreement are included in other purchase obligations in the Future Cash Requirements for Operations and Capital Expenditures under Executed Contracts table below. Full discussion of the partial TUA assignment and SPLNG's TUA agreements can be found in Note 13—Revenues of our Notes to Consolidated Financial Statements.

Additional Future Sources of Liquidity

Available Commitments under Credit Facilities

As of December 31, 2022, we had $1.6 billion in available commitments under our credit facilities, subject to compliance with the applicable covenants, to potentially meet liquidity needs. Our credit facilities mature between 2024 and 2025.

Future Cash Requirements for Operations and Capital Expenditures under Executed Contracts

We are committed to make future cash payments for operations and capital expenditures pursuant to certain of our contracts. The following table summarizes our estimate of material cash requirements for operations and capital expenditures under executed contracts as of December 31, 2022 (in billions):

	Estimated Payments Due Under Executed Contracts by Period (1)			
	2023	**2024 - 2027**	**Thereafter**	**Total**
Purchase obligations (2):				
Natural gas supply agreements (3)	$ 6.4	$ 12.7	$ 7.3	$ 26.4
Natural gas transportation and storage service agreements (4)	0.3	1.1	2.3	3.7
Other purchase obligations (5)	0.3	0.9	1.2	2.4
Leases (6)	—	0.1	0.1	0.2
Total	$ 7.0	$ 14.8	$ 10.9	$ 32.7

(1) Agreements in force as of December 31, 2022 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2022. The estimates above reflect management's assumptions and currently known market conditions and other factors as of December 31, 2022. 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.

(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 conditions precedent 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, 2022. Pricing of our IPM agreement is based on global gas market prices less fixed liquefaction fees and certain costs incurred by us. Includes $0.4 billion under natural gas supply agreements with unsatisfied conditions precedent.

(4) Includes $0.3 billion of purchase obligations to related parties under the natural gas transportation and storage service agreements.

(5) Other purchase obligations include payments under SPL's partial TUA assignment agreement with TotalEnergies, as discussed in *Regasification Revenues* above, and $1.3 billion of purchase obligations to affiliates under service agreements.

(6) Leases include 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 the payment of a fixed amount that is 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 Sabine Pass LNG Terminal through long-term natural gas supply and 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 LNG market price paid for the natural gas feedstock purchase.

As of December 31, 2022, we have secured approximately 84% of the natural gas supply required to support the total forecasted production capacity of the Liquefaction Project during 2023. Natural gas supply secured decreases as a percentage of forecasted production capacity beyond 2023. Natural gas supply is generally secured on an indexed pricing basis, 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 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 conditions precedent as of December 31, 2022, we have secured up to 5,785 TBtu of natural gas feedstock through agreements with remaining terms that range up to 15 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 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

Corporate Activities

We rely on our general partner to manage all aspects of the development, construction, operation and maintenance of the Sabine Pass LNG Terminal and the Liquefaction Project 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, 2022, Cheniere and its subsidiaries had 1,551 full-time employees, including 517 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. We expect that any potential future expansion at the Sabine Pass LNG Terminal would increase cash requirements to support expanded operations, although expansion could 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, 2022 (in billions):

	Estimated Payments Due Under Executed Contracts by Period (1)			
	2023	**2024 - 2027**	**Thereafter**	**Total**
Debt (2)	$ —	$ 7.2	$ 9.1	$ 16.3
Interest payments (2)	0.8	2.3	1.2	4.3
Total	$ 0.8	$ 9.5	$ 10.3	$ 20.6

(1) The estimates above reflect management's assumptions and currently known market conditions and other factors as of December 31, 2022. 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.

(2) 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, 2022. Debt and interest payments do not contemplate repurchases, repayments and retirements that we expect to make prior to contractual maturity. See further discussion in Note 11—Debt of our Notes to Consolidated Financial Statements.

Debt

As of December 31, 2022, our debt complex was comprised of senior notes with an aggregate outstanding principal balance of $16.3 billion and credit facilities with no outstanding balances. As of December 31, 2022, 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, 2022, our senior notes had a weighted average contractual interest rate of 4.83%. Borrowings under our credit facilities are indexed to LIBOR, which is expected to be phased out in 2023. We intend to continue working with our lenders to pursue amendments to our debt agreements that are currently indexed to LIBOR. Undrawn commitments under our credit facilities are subject to commitment fees ranging from 0.10% to 0.638%, 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 1.125% to 1.75%. We had $328 million aggregate amount of issued letters of credit under our credit facilities as of December 31, 2022.

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 (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.

Revised 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. During the year ended December 31, 2022, $1.5 billion of 2023 SPL Senior Notes were redeemed pursuant to the capital allocation plan.

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,	
	2022	2021
Net cash provided by operating activities	$ 4,149	$ 2,291
Net cash used in investing activities	(451)	(648)
Net cash used in financing activities	(3,676)	(1,976)
Net increase (decrease) in cash, cash equivalents and restricted cash and cash equivalents	$ 22	$ (333)

Operating Cash Flows

Our operating cash net inflows during the years ended December 31, 2022 and 2021 were $4.1 billion and $2.3 billion, respectively. The $1.9 billion increase was primarily related to increased cash receipts from the sale of LNG cargoes due to higher revenue per MMBtu, higher volume of LNG delivered. Additionally, a portion of the increase was related to the receipt of the lump sum Termination Fee from Chevron related to the Termination Agreement, as further described in Overview of Significant Events, of which $796 million of cash inflows were allocable to the termination of the TUA, while an offsetting $31 million was recognized as a loss on extinguishment of debt allocable to a premium paid to Chevron to terminate a revenue sharing arrangement with them that was accounted for as debt, as discussed below under *Financing Cash Flows*. Partially offsetting these operating cash inflows were higher operating cash outflows primarily due to higher natural gas feedstock costs.

Investing Cash Flows

Cash outflows for property, plant and equipment were primarily for the construction costs for Train 6 of the Liquefaction Project, which achieved substantial completion on February 4, 2022.

Financing Cash Flows

Our financing cash net outflows during the years ended December 31, 2022 and 2021 were $3.7 billion and $2.0 billion, respectively. The $1.7 billion increase in outflows between the periods was primarily related to an increase in cash distributions to unitholders of $1.2 billion and an increase of $507 million of net outflows related to debt activity, each described further below.

Debt Activity

During the year ended December 31, 2022, SPL issued an aggregate principal amount of $430 million of 5.900% SPL Senior Notes and $70 million of 6.293% SPL Senior Notes. We incurred $7 million of debt issuance costs related to these issuances. The proceeds of these issuances, together with cash on hand, were used to redeem $1.5 billion in aggregate principal amount of 2023 SPL Senior Notes. We paid $1 million of debt extinguishment costs related to premiums associated with this redemption. Additionally, during the year ended December 31, 2022, we had borrowings and repayments of $60 million on the SPL Working Capital Facility. In addition, during the year ended December 31, 2022, we paid $31 million loss on extinguishment associated with the Termination Agreement with Chevron.

During the year ended December 31, 2021, we issued an aggregate principal amount of $1.5 billion of the 2031 CQP Senior Notes and $1.2 billion of the 3.25% Senior Notes due 2032 (the “2032 CQP Senior Notes”), and SPL issued $482 million of Senior Secured Notes due 2037 on a private placement basis (the “2037 SPL Private Placement Notes”). We incurred $39 million of debt issuance costs related to these issuances. The proceeds of these issuances, together with cash on hand, were used to redeem the $1.5 billion principal amount of the 2025 CQP Senior Notes, $1.1 billion of the 2026 CQP Senior Notes and $1.0 billion of SPL’s 6.25% Senior Secured Notes due 2022. We paid $76 million of debt extinguishment costs related to premiums associated with this redemption.

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, 2022 and 2021:

			Total Distribution (in millions)		
Date Paid	**Period Covered by Distribution**	**Distribution Per Common Unit**	**Common Units**	**General Partner Units**	**Incentive Distribution Rights**
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
November 12, 2021	July 1 - September 30, 2021	$ 0.680	$ 329	$ 8	$ 39
August 13, 2021	April 1 - June 30, 2021	0.665	322	7	32
May 14, 2021	January 1 - March 31, 2021	0.660	320	7	30
February 12, 2021	October 1 - December 31, 2020	0.655	316	7	27

In addition, Tug Services distributed $12 million and $9 million during the years ended December 31, 2022 and 2021, 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 27, 2023, we declared a cash distribution of $1.07 per common unit to unitholders of record as of February 6, 2023 and the related general partner distribution that was paid on February 14, 2023. These distributions consist of a base amount of $0.775 per unit and a variable amount of $0.295 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 derivative instruments are recorded at fair value, other than certain derivatives for which we have elected to apply accrual accounting, 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 would use in valuing the asset or liability. This includes assumptions about market risks, such as future prices of energy units for unobservable periods, liquidity and adjustments for transportation prices, and associated events deriving fair value, including, but not limited to, evaluation of whether the respective market exists from the perspective of market participants as infrastructure is developed.

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, 2022 and 2021 (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,	
	2022	**2021**
Favorable (unfavorable) changes in fair value relating to instruments still held at the end of the period	$ (1,032)	$ 74

The unfavorable change in unrealized loss on instruments held at December 31, 2022 is primarily attributed to the assignment of an IPM agreement to SPL in March 2022, which is valued based on estimated forward international LNG commodity curves. For additional discussion of the assignment of the IPM agreement, see Note 18—Supplemental Cash Flow Information of our Notes to Consolidated Financial Statements.

The estimated fair value of level 3 derivatives recognized in our Consolidated Balance Sheets as of December 31, 2022 and 2021 amounted to an asset (liability) of $(3.7) billion and $38 million, 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

We have entered into commodity derivatives consisting of natural gas supply contracts for the operation of the Liquefaction Project ("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, 2022		December 31, 2021	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
Liquefaction Supply Derivatives	$ (3,741)	$ 565	$ 27	$ 1

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, 2022, 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, 2022, 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 President and Chief Executive Officer (Principal Executive Officer)		Zach Davis 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, 2022 and 2021, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2022, 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, 2022, 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 22, 2023 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 physical liquefaction supply derivatives

As discussed in Notes 3 and 8 to the consolidated financial statements, the Partnership recorded fair value of level 3 physical liquefaction supply derivatives of $(3,719) million, as of December 31, 2022. The physical liquefaction supply derivatives consist of natural gas supply contracts for the operation of the liquefied natural gas facility. The fair value of the level 3 physical liquefaction supply derivatives is developed using internal models that incorporate significant unobservable inputs.

We identified the evaluation of the fair value of the level 3 physical liquefaction supply derivatives as a critical audit matter. Specifically, there is subjectivity in certain assumptions used to estimate the fair value, including assumptions for future prices of energy units for unobservable periods and liquidity.

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 the level 3 physical liquefaction supply derivatives. This included controls related to the assumptions for significant unobservable inputs and the fair value model. For a selection of level 3 liquefaction supply derivatives, we involved valuation professionals with specialized skills and knowledge who assisted in:

- evaluating the future prices of energy units for observable periods by comparing to market data, including quoted or published forward prices
- developing independent fair value estimates and comparing the independently developed estimates to the Company's fair value estimates.

In addition, we evaluated the Partnership's assumptions for future prices of energy units for unobservable periods and liquidity by comparing them to market or third-party data, including adjustments for third party quoted transportation prices.

/s/ KPMG LLP

KPMG LLP

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

Houston, Texas
February 22, 2023

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, 2022, 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, 2022, 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, 2022 and 2021, 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, 2022, and the related notes and financial statement schedule I (collectively, the consolidated financial statements), and our report dated February 22, 2023 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 22, 2023

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CONSOLIDATED STATEMENTS OF INCOME

(in millions, except per unit data)

	Year Ended December 31, 2022	2021	2020
Revenues			
LNG revenues	$ 11,507	$ 7,639	$ 5,195
LNG revenues—affiliate	4,568	1,472	662
LNG revenues—related party	—	1	—
Regasification revenues	1,068	269	269
Other revenues	63	53	41
Total revenues	17,206	9,434	6,167
Operating costs and expenses			
Cost of sales (excluding items shown separately below)	11,887	5,290	2,505
Cost of sales—affiliate	213	84	77
Cost of sales—related party	—	17	—
Operating and maintenance expense	757	635	629
Operating and maintenance expense—affiliate	166	142	152
Operating and maintenance expense—related party	72	46	13
General and administrative expense	5	9	14
General and administrative expense—affiliate	92	85	96
Depreciation and amortization expense	634	557	551
Other	—	11	5
Other—affiliate	—	1	—
Total operating costs and expenses	13,826	6,877	4,042
Income from operations	3,380	2,557	2,125
Other income (expense)			
Interest expense, net of capitalized interest	(870)	(831)	(909)
Loss on modification or extinguishment of debt	(33)	(101)	(43)
Other income, net	21	3	8
Other income—affiliate	—	2	2
Total other expense	(882)	(927)	(942)
Net income	$ 2,498	$ 1,630	$ 1,183
Basic and diluted net income per common unit (1)	$ 3.27	$ 3.00	$ 2.32
Weighted average basic and diluted number of common units outstanding	484.0	484.0	399.3

(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, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	$ 904	$ 876
Restricted cash and cash equivalents	92	98
Trade and other receivables, net of current expected credit losses	627	580
Accounts receivable—affiliate	551	232
Accounts receivable—related party	—	1
Advances to affiliate	177	141
Inventory	160	176
Current derivative assets	24	21
Margin deposits	35	7
Other current assets	50	80
Total current assets	2,620	2,212
Property, plant and equipment, net of accumulated depreciation	16,725	16,830
Operating lease assets	89	98
Debt issuance costs, net of accumulated amortization	8	12
Derivative assets	28	33
Other non-current assets, net	163	173
Total assets	$ 19,633	$ 19,358
LIABILITIES AND PARTNERS’ EQUITY (DEFICIT)		
Current liabilities		
Accounts payable	$ 32	$ 21
Accrued liabilities	1,378	1,073
Accrued liabilities—related party	6	4
Due to affiliates	74	67
Deferred revenue	144	155
Deferred revenue—affiliate	3	1
Current operating lease liabilities	10	8
Current derivative liabilities	769	16
Other current liabilities	5	—
Total current liabilities	2,421	1,345
Long-term debt, net of premium, discount and debt issuance costs	16,198	17,177
Operating lease liabilities	80	89
Finance lease liabilities	18	—
Derivative liabilities	3,024	11
Other non-current liabilities—affiliate	23	18
Commitments and contingencies (see Note 16)		
Partners’ equity (deficit)		
Common unitholders’ interest (484.0 million units issued and outstanding at both December 31, 2022 and 2021)	(1,118)	1,024
General partner’s interest (2% interest with 9.9 million units issued and outstanding at both December 31, 2022 and 2021)	(1,013)	(306)
Total partners’ equity (deficit)	(2,131)	718
Total liabilities and partners’ equity (deficit)	$ 19,633	$ 19,358

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		Subordinated Unitholder's Interest		General Partner's Interest		Total Partners' Equity (Deficit)
	Units	Amount	Units	Amount	Units	Amount	
Balance at December 31, 2019	348.6	$ 1,792	135.4	$ (996)	9.9	$ (81)	$ 715
Net income	—	930	—	229	—	24	1,183
Conversion of subordinated units into common units	135.4	(1,026)	(135.4)	1,026	—	—	—
Distributions							
Common units, $2.57/unit	—	(982)	—	—	—	—	(982)
Subordinated units, $2.57/unit	—	—	—	(259)	—	—	(259)
General partner units	—	—	—	—	—	(118)	(118)
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)

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,		
	2022	2021	2020
Cash flows from operating activities			
Net income	$ 2,498	$ 1,630	$ 1,183
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	634	557	551
Amortization of debt issuance costs, premium and discount	30	29	32
Loss on modification or extinguishment of debt	33	101	43
Total losses (gains) on derivative instruments, net	1,158	(29)	49
Total gains on derivatives instruments, net—related party	—	(2)	—
Net cash used for settlement of derivative instruments	(102)	(17)	(4)
Other	44	27	19
Other—affiliate	—	—	(2)
Changes in operating assets and liabilities:			
Trade and other receivables, net of current expected credit losses	(112)	(204)	(21)
Accounts receivable—affiliate	(335)	(32)	(80)
Accounts receivable—related party	—	(1)	—
Advances to affiliate	(36)	2	8
Inventory	12	(68)	8
Margin deposits	(28)	(3)	(2)
Accounts payable and accrued liabilities	354	321	—
Accrued liabilities—related party	3	(1)	4
Due to affiliates	20	1	9
Deferred revenue	(11)	18	(18)
Other, net	(24)	(38)	(26)
Other, net—affiliate	11	—	(2)
Net cash provided by operating activities	4,149	2,291	1,751
Cash flows from investing activities			
Property, plant and equipment	(451)	(648)	(972)
Net cash used in investing activities	(451)	(648)	(972)
Cash flows from financing activities			
Proceeds from issuances of debt	559	3,182	1,995
Redemptions and repayments of debt	(1,560)	(3,600)	(2,000)
Debt issuance and other financing costs	(7)	(39)	(35)
Debt extinguishment costs	(32)	(76)	(39)
Distributions	(2,635)	(1,451)	(1,359)
Other	(1)	8	4
Net cash used in financing activities	(3,676)	(1,976)	(1,434)
Net increase (decrease) in cash, cash equivalents and restricted cash and cash equivalents	22	(333)	(655)
Cash, cash equivalents and restricted cash and cash equivalents—beginning of period	974	1,307	1,962
Cash, cash equivalents and restricted cash and cash equivalents—end of period	$ 996	$ 974	$ 1,307

Balances per Consolidated Balance Sheets:

	December 31,	
	2022	2021
Cash and cash equivalents	$ 904	$ 876
Restricted cash and cash equivalents	92	98
Total cash, cash equivalents and restricted cash and cash equivalents	$ 996	$ 974

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, with Train 6 having achieved substantial completion on February 4, 2022, for a total operational 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, with the third berth having achieved substantial completion on October 27, 2022. We also own a 94-mile pipeline through our subsidiary, CTPL, that interconnects the Sabine Pass LNG Terminal with a number of large interstate and intrastate pipelines (the "Creole Trail Pipeline").

We have increased available liquefaction capacity at our Liquefaction Project as a result of debottlenecking and other optimization projects. We hold a significant land position at the Sabine Pass LNG Terminal, which provides opportunity for further liquefaction capacity expansion. The development of this site 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 final investment decision.

As of December 31, 2022, 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 (as defined in our partnership agreement). Generally, 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 we have paid to date have been made from accumulated operating surplus as defined in the partnership agreement.

As of December 31, 2022, our total securities beneficially owned in the form of common units were held 48.6% by Cheniere, 41.4% by CQP Target Holdco L.L.C. ("CQP Target Holdco") and other affiliates of Blackstone Inc. ("Blackstone") and Brookfield Asset Management Inc. ("Brookfield") and 8.0% 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.

Use of 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, certain valuations including leases and asset retirement obligations ("AROs") 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 maximize the 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 inNote 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. Debt fair values, as disclosed in Note 11—Debt, are based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments using observable or unobservable inputs.

Revenue Recognition

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

Cash and Cash Equivalents

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

Restricted Cash and Cash Equivalents

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

Current Expected Credit Losses

Trade and other receivables and contract assets are reported net of any current expected credit losses. Current expected credit losses consider the risk of loss based on past events, current conditions and reasonable and supportable forecasts. A counterparty's ability to pay is assessed through a credit review process that considers payment terms, the counterparty's established credit rating or our assessment of the counterparty's credit worthiness, contract terms, payment status and other risks or available financial assurances. Adjustments to current expected credit losses are recorded in general and administrative expense in our Consolidated Statements of Income. As of December 31, 2022 and 2021, we had current expected credit losses of zero and $5 million, respectively, on our trade and other receivables, and as of both December 31, 2022 and 2021, we had current expected credit losses of zero on our non-current contract assets.

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 front-end engineering and design work, 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, 2022, 2021 and 2020.

Interest Capitalization

We capitalize interest costs during the construction period of our LNG terminal and related assets as construction-in-process. Upon placing the underlying asset in service, these costs are transferred out of construction-in-process into the respective in-service asset category and depreciated over the estimated useful life of the corresponding assets, except for capitalized interest associated with land, which is not depreciated.

Regulated Natural Gas Pipelines

The Creole Trail Pipeline is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. The economic effects of regulation can result in a regulated company recording as assets those costs that have been or are expected to be approved for recovery from customers, or recording as liabilities those amounts that are expected to be required to be returned to customers, in a rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, we record assets and liabilities that result from the regulated rate-making process that may not be recorded under GAAP for non-regulated entities. We continually assess whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Based on this continual assessment, we believe the existing regulatory assets are probable of recovery. These regulatory assets and liabilities are classified in our Consolidated Balance Sheets as other assets and other liabilities. Upon a triggering event, we evaluate their applicability under GAAP and consider factors such as regulatory changes and the effect of competition. If cost-based regulation ends or competition increases, we may have to write off the associated regulatory assets and liabilities.

Items that may influence our assessment are:

- inability to recover cost increases due to rate caps and rate case moratoriums;
- inability to recover capitalized costs, including an adequate return on those costs through the rate-making process and the FERC proceedings;
- excess capacity;
- increased competition and discounting in the markets we serve; and
- impacts of ongoing regulatory initiatives in the natural gas industry.

Natural gas pipeline costs include amounts capitalized as an Allowance for Funds Used During Construction ("AFUDC"). The rates used in the calculation of AFUDC are determined in accordance with guidelines established by the FERC. AFUDC represents the cost of debt and equity funds used to finance our natural gas pipeline additions during construction. AFUDC is capitalized as a part of the cost of our natural gas pipeline. Under regulatory rate practices, we generally are permitted to recover AFUDC, and a fair return thereon, through our rate base after the natural gas pipelines are placed in service.

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 assets or liabilities depending on the derivative position and the expected timing of settlement, unless they satisfy criteria for, and we elect, the normal purchases and sales exception, under which we account for the instrument under the accrual method of accounting, whereby revenues and expenses are recognized only upon delivery, receipt or realization of the underlying transaction. When we have the contractual right and intent to net settle, derivative assets and liabilities are reported on a net basis.

For those derivative instruments measured at fair value, changes in the fair value of the instruments are recorded in earnings, unless we elect to apply hedge accounting and meet specified criteria. We did not have any derivative instruments designated as cash flow or fair value hedges during the years ended December 31, 2022, 2021 and 2020. 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, 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 implicitly 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 contract terms require the payment of a fixed amount that is unavoidable.

See Note 12—Leases for additional details about our leases.

Concentration of Credit Risk

Financial instruments that potentially subject us to a concentration of credit risk consist principally of derivative instruments and accounts receivable 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. 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.

SPL has entered into fixed price long-term SPAs generally with terms of20 years with 11 third parties and has entered into agreements with Cheniere Marketing. SPL is dependent on the respective customers' creditworthiness and their willingness to perform under their respective SPAs.

See Note 17—Customer Concentration for additional details about our customer concentration.

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. Gains and losses on the extinguishment or modification of debt are recorded in loss on modification or extinguishment of debt on our Consolidated Statements of Income.

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.

Income Taxes

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, 2022, the tax basis of our assets and liabilities was $7.7 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.

Business Segment

Our liquefaction and regasification operations at the Sabine Pass LNG Terminal represent a single reportable segment. Our chief operating decision maker reviews the financial results of CQP in total when evaluating financial performance and for purposes of allocating resources.

Recent Accounting Standards

ASU 2020-04

In March 2020, the FASB issued ASU 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 debt agreements expected to arise from 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. We have not yet applied the optional expedients available under the standard because we have not yet modified any of our existing contracts indexed to LIBOR, mainly our credit facilities as further described in Note 11—Debt, for reference rate reform. However, we do not expect the impact of applying the optional expedients to any future contract modifications to be material, and we do not expect the transition to a replacement rate index to have a material impact on our future cash flows.

NOTE 4—RESTRICTED CASH AND CASH EQUIVALENTS

Pursuant to the accounts agreement entered into with the collateral trustee for the benefit of SPL's debt holders, SPL is required to deposit all cash received into reserve accounts controlled by the collateral trustee. The usage or withdrawal of such cash is restricted to the payment of liabilities related to the Liquefaction Project and other restricted payments.

As of December 31, 2022 and 2021, we had $92 million and $98 million of restricted cash and cash equivalents, respectively, as required under the above agreement.

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,	
	2022	2021
Trade receivables	$ 603	$ 546
Other receivables	24	34
Total trade and other receivables, net of current expected credit losses	$ 627	$ 580

NOTE 6—INVENTORY

Inventory consisted of the following (in millions):

	December 31,	
	2022	2021
Materials	$ 103	$ 86
LNG	27	45
Natural gas	28	43
Other	2	2
Total inventory	$ 160	$ 176

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,	
	2022	2021
LNG terminal		
Terminal and interconnecting pipeline facilities	$ 20,072	$ 16,973
Construction-in-process	140	2,746
Accumulated depreciation	(3,512)	(2,893)
Total LNG terminal, net of accumulated depreciation	16,700	16,826
Fixed assets		
Fixed assets	29	29
Accumulated depreciation	(25)	(25)
Total fixed assets, net of accumulated depreciation	4	4
Assets under finance leases		
Tug vessels	23	—
Accumulated depreciation	(2)	—
Total assets under finance lease, net of accumulated depreciation	21	—
Property, plant and equipment, net of accumulated depreciation	$ 16,725	$ 16,830

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

	Year Ended December 31,		
	2022	2021	2020
Depreciation expense	$ 630	$ 552	$ 547
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 Lease

Our assets under finance lease 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 entered into commodity derivatives consisting of natural gas supply contracts, including those under SPL's IPM agreement, for the operation of the Liquefaction Project and associated economic hedges (collectively, "Liquefaction Supply Derivatives").

We recognize our derivative instruments as either assets or liabilities and measure those instruments at fair value. None of our derivative instruments are designated as cash flow or fair value 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 that are required to be measured at fair value on a recurring basis (in millions):

	Fair Value Measurements as of							
	December 31, 2022				December 31, 2021			
	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)	$ (12)	$ (10)	$ (3,719)	$ (3,741)	$ 2	$ (13)	$ 38	$ 27

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

The fair value of our Liquefaction Supply Derivatives is predominantly driven by observable and unobservable market commodity prices and, as applicable to our natural gas supply contracts, our assessment of the associated events deriving fair value including, but not limited to, evaluation of whether the respective market exists from the perspective of market participants as infrastructure is developed.

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 would use in valuing the asset or liability. This includes assumptions about market risks, such as future prices of energy units for unobservable periods, liquidity and volatility.

The Level 3 fair value measurements of natural gas positions within our Liquefaction Supply Derivatives could be materially impacted by a significant change in certain natural gas and international LNG prices. The following table includes quantitative information for the unobservable inputs for our Level 3 Liquefaction Supply Derivatives as of December 31, 2022:

	Net Fair Value Liability (in millions)	Valuation Approach	Significant Unobservable Input	Range of Significant Unobservable Inputs / Weighted Average (1)
Liquefaction Supply Derivatives	$(3,719)	Market approach incorporating present value techniques	Henry Hub basis spread	$(1.775) - $0.660 / $(0.063)
		Option pricing model	International LNG pricing spread, relative to Henry Hub (2)	77% - 515% / 193%

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

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

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

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

	Year Ended December 31,		
	2022	2021	2020
Balance, beginning of period	$ 38	$ (21)	$ 24
Realized and change in fair value gains (losses) included in net income (1):			
Included in cost of sales, existing deals (2)	(228)	74	(43)
Included in cost of sales, new deals (3)	(804)	—	—
Purchases and settlements:			
Purchases (4)	(2,712)	(10)	5
Settlements (5)	(13)	(5)	(7)
Balance, end of period	$ (3,719)	$ 38	$ (21)
Favorable (unfavorable) changes in fair value relating to instruments still held at the end of the period	$ (1,032)	$ 74	$ (43)

(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 IPM agreements that were novated to us during the period, 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.

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

Liquefaction Supply Derivatives

SPL holds Liquefaction Supply Derivatives which are primarily indexed to the natural gas market and international LNG indices. The terms of the Liquefaction Supply Derivatives range up to 15 years, some of which commence upon the satisfaction of certain events or states of affairs.

The forward notional amount for our Liquefaction Supply Derivatives was approximately5,972 TBtu and 5,194 TBtu as of December 31, 2022 and 2021, respectively, excluding notional amounts associated with extension options that were uncertain to be taken as of December 31, 2022.

The following table shows the effect and location of our 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)	2022	2021	2020
LNG revenues	$ 1	$ (1)	$ —
Cost of sales	(1,159)	30	(49)
Cost of sales—related party	—	2	—

(1) Does not include the value associated with derivative instruments 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 our Liquefaction Supply Derivatives on our Consolidated Balance Sheets (in millions):

	Fair Value Measurements as of (1)	
Consolidated Balance Sheets Location	December 31, 2022	December 31, 2021
Current derivative assets	$ 24	$ 21
Derivative assets	28	33
Total derivative assets	52	54
Current derivative liabilities	(769)	(16)
Derivative liabilities	(3,024)	(11)
Total derivative liabilities	(3,793)	(27)
Derivative asset (liability), net	$ (3,741)	$ 27

(1) Does not include collateral posted with counterparties by us of $35 million and $7 million, as of December 31, 2022 and 2021, respectively, which are included in margin deposits in our Consolidated Balance Sheets.

Consolidated Balance Sheets Presentation

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

	Liquefaction Supply Derivatives
As of December 31, 2022	
Gross assets	$ 57
Offsetting amounts	(5)
Net assets	$ 52
Gross liabilities	$ (3,814)
Offsetting amounts	21
Net liabilities	$ (3,793)
As of December 31, 2021	
Gross assets	$ 79
Offsetting amounts	(25)
Net assets	$ 54
Gross liabilities	$ (33)
Offsetting amounts	6
Net liabilities	$ (27)

NOTE 9—OTHER NON-CURRENT ASSETS, NET

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

	December 31, 2022	December 31, 2021
Advances made to municipalities for water system enhancements	$ 78	$ 81
Advances and other asset conveyances to third parties to support LNG terminal	31	37
Advances made under EPC and non-EPC contracts	—	5
Tax-related prepayments and receivables	17	15
Information technology service prepayments	5	5
Other	32	30
Total other non-current assets, net	$ 163	$ 173

NOTE 10—ACCRUED LIABILITIES

Accrued liabilities consisted of the following (in millions):

	December 31, 2022	December 31, 2021
Natural gas purchases	$ 1,017	$ 786
Interest costs and related debt fees	218	180
LNG terminal and related pipeline costs	137	101
Other accrued liabilities	6	6
Total accrued liabilities	$ 1,378	$ 1,073

NOTE 11—DEBT

Debt consisted of the following (in millions):

	December 31, 2022	December 31, 2021
SPL:		
Senior Secured Notes:		
5.625% due 2023	$ —	$ 1,500
5.75% due 2024	2,000	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	1,282
Total SPL Senior Secured Notes	12,132	13,132
Working capital revolving credit and letter of credit reimbursement agreement (the “SPL Working Capital Facility”)	—	—
Total debt - SPL	12,132	13,132
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
Total CQP Senior Notes	4,200	4,200
Credit facilities (the “CQP Credit Facilities”)	—	—
Total debt - CQP	4,200	4,200
Total debt	16,332	17,332
Unamortized premium, discount and debt issuance costs, net	(134)	(155)
Total long-term debt, net of premium, discount and debt issuance costs	$ 16,198	$ 17,177

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 and 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 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 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, 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, 2022 (in millions):

Years Ending December 31,	Principal Payments
2023	$ —
2024	2,000
2025	2,051
2026	1,608
2027	1,612
Thereafter	9,061
Total	$ 16,332

Credit Facilities

Below is a summary of our credit facilities outstanding as of December 31, 2022 (in millions):

	SPL Working Capital Facility (1)	CQP Credit Facilities (2)
Total facility size	$ 1,200	$ 750
Less:		
Outstanding balance	—	—
Letters of credit issued	328	—
Available commitment	$ 872	$ 750
Priority ranking	Senior secured	Unsecured
Interest rate on available balance (3)	LIBOR plus 1.125% - 1.750% or base rate plus 0.125% - 0.750%	LIBOR plus 1.25% - 2.125% or base rate plus 0.25% - 1.125%
Commitment fees on undrawn balance (3)	0.10% - 0.30%	0.375% - 0.638%
Maturity date	March 19, 2025	May 29, 2024

(1) The obligations of SPL under the SPL Working Capital 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 Working Capital Facility contains customary conditions precedent for extensions.

(2) The obligations under the CQP Credit Facilities are unconditionally guaranteed by the CQP Guarantors.

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

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

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

Restrictive Debt Covenants

The indentures governing our senior notes and other agreements underlying our debt contain customary terms and events of default and certain covenants that, among other things, may limit us and our restricted subsidiaries' ability to make certain investments or pay dividends or distributions. We and SPL are restricted from making distributions under agreements governing our and SPL's 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, 2022, our restricted net liabilities of consolidated subsidiaries were approximately $1.8 billion.

As of December 31, 2022, 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,		
	2022	2021	2020
Total interest cost	$ 910	$ 963	$ 1,005
Capitalized interest	(40)	(132)	(96)
Total interest expense, net of capitalized interest	$ 870	$ 831	$ 909

Fair Value Disclosures

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

	December 31, 2022		December 31, 2021	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Senior notes — Level 2 (1)	$ 14,980	$ 14,162	$ 16,050	$ 17,496
Senior notes — Level 3 (2)	1,352	1,224	1,282	1,466

(1) The Level 2 estimated fair value was based on quotes obtained from broker-dealers or market makers of these senior notes and other similar instruments.

(2) The Level 3 estimated fair value was calculated based on inputs that are observable in the market or that could be derived from, or corroborated with, observable market data, including interest rates based on debt issued by parties with comparable credit ratings to us and inputs that are not observable in the market.

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):

		December 31,	
	Consolidated Balance Sheets Location	2022	2021
Right-of-use assets—Operating	Operating lease assets	$ 89	$ 98
Right-of-use assets—Financing	Property, plant and equipment, net of accumulated depreciation	21	—
Total right-of-use assets		$ 94	$ 98
Current operating lease liabilities	Current operating lease liabilities	10	8
Current finance lease liabilities	Other current liabilities	4	—
Non-current operating lease liabilities	Operating lease liabilities	80	89
Non-current finance lease liabilities	Finance lease liabilities	18	—
Total lease liabilities		$ 112	97

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

		Year Ended December 31,		
	Consolidated Statements of Income Location	2022	2021	2020
Operating lease cost (1)	Operating costs and expenses (2)	$ 13	$ 12	$ 12
Finance lease cost:				
Amortization of right-of-use assets	Depreciation and amortization expense	2	—	—
Total lease cost		$ 15	$ 12	$ 12

(1) Includes $1 million of variable lease costs incurred during each of the years ended December 31, 2022, 2021 and 2020, 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, 2022 are as follows (in millions):

Years Ending December 31,	Operating Leases	Finance Leases
2023	$ 12	$ 6
2024	12	5
2025	12	5
2026	12	5
2027	12	5
Thereafter	94	—
Total lease payments	154	26
Less: Interest	(64)	(4)
Present value of lease liabilities	$ 90	$ 22

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, 2022		December 31, 2021	
	Operating Leases	Finance Leases	Operating Leases	Finance Leases
Weighted-average remaining lease term (in years)	23.8	5.1	23.4	0.0
Weighted-average discount rate	3.8 %	4.8 %	3.6 %	— %

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

	Year Ended December 31,		
	2022	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	10	11	11
Leased assets obtained in exchange for new operating lease liabilities	—	7	11
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,		
	2022	2021	2020
Revenues from contracts with customers			
LNG revenues (1)	$ 11,506	$ 7,640	$ 5,195
LNG revenues—affiliate	4,568	1,472	662
LNG revenues—related party	—	1	—
Regasification revenues	1,068	269	269
Other revenues	63	53	41
Total revenues from contracts with customers	17,205	9,435	6,167
Net derivative gain (loss) (2)	1	(1)	—
Total revenues	$ 17,206	$ 9,434	$ 6,167

(1) LNG revenues include revenues for LNG cargoes in which our customers exercised their contractual right to not take delivery but remained obligated to pay fixed fees irrespective of such election. During the year ended December 31, 2020, we recognized $553 million in LNG revenues associated with LNG cargoes for which customers notified us that they would not take delivery. We did not have revenues associated with LNG cargoes for which customers notified us that they would not take delivery during the years ended December 31, 2022 and 2021. Revenue is generally recognized upon receipt of irrevocable notice that a customer will not take delivery because our customers have no contractual right to take delivery of such LNG cargo in future periods and our performance obligations with respect to such LNG cargo have been satisfied.

(2) 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 a free on board ("FOB") (delivered to the customer at the Sabine Pass LNG Terminal) basis. 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. The stated contract price (including both fixed and variable fees) per MMBtu in each LNG sales arrangement is representative of the stand-alone selling price for LNG at 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. During the years ended December 31, 2022, 2021 and 2020, SPL recorded $131 million, $129 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 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 and other non-current assets, net on our Consolidated Balance Sheets (in millions):

	December 31,	
	2022	2021
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 on our Consolidated Balance Sheets (in millions):

	Year Ended December 31, 2022
Deferred revenue, beginning of period	$ 155
Cash received but not yet recognized in revenue	144
Revenue recognized from prior period deferral	(155)
Deferred revenue, end of period	$ 144

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, 2022
Deferred revenue—affiliate, beginning of period	$ 3
Cash received but not yet recognized in revenue	8
Revenue recognized from prior period deferral	(3)
Deferred revenue—affiliate, end of period	$ 8

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, 2022 and 2021 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, 2022		December 31, 2021	
	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)
LNG revenues	$ 50.8	8	$ 49.3	9
LNG revenues—affiliate	2.0	2	2.1	3
Regasification revenues	0.8	4	1.9	4
Total revenues	$ 53.6		$ 53.3	

(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.

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 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. Approximately 74% and 61% of our LNG revenues from contracts included in the table above during the years ended December 31, 2022 and 2021, respectively, were related to variable consideration received from customers. Approximately 75% and 96% of our LNG revenues—affiliate from contracts included in the table above during the years ended December 31, 2022 and 2021, respectively, were related to variable consideration received from customers. During the years ended December 31, 2022 and 2021, approximately 2% and 5%, respectively, of our regasification revenues were related to variable consideration received from customers.

We may enter into contracts to sell LNG that are conditioned upon one or both of the parties achieving certain milestones such as reaching a final investment decision 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.

NOTE 14—RELATED PARTY TRANSACTIONS

Below is a summary of our related party transactions as reported on our Consolidated Statements of Income (in millions):

	Year Ended December 31,		
	2022	2021	2020
LNG revenues—affiliate			
Cheniere Marketing Agreements (1)	$ 4,565	$ 1,453	$ 632
Contracts for Sale and Purchase of Natural Gas and LNG (2)	3	19	30
Total LNG revenues—affiliate	4,568	1,472	662
LNG revenues—related party			
Natural Gas Transportation and Storage Agreements (3)	—	1	—
Cost of sales—affiliate			
Cheniere Marketing Agreements (1)	—	34	61
Contracts for Sale and Purchase of Natural Gas and LNG (2)	213	50	16
Total cost of sales—affiliate	213	84	77
Cost of sales—related party			
Natural Gas Transportation and Storage Agreements (3)	—	1	—
Natural Gas Supply Agreements (1)	—	16	—
Total cost of sales—related party	—	17	—
Operating and maintenance expense—affiliate			
Services Agreements (4)	166	142	152
Operating and maintenance expense—related party			
Natural Gas Transportation and Storage Agreements (3)	72	46	13
General and administrative expense—affiliate			
Services Agreements (4)	92	85	96
Other income—affiliate			
Cooperative Endeavor Agreement (5)	—	2	2

(1) SPL primarily sells LNG to Cheniere Marketing under SPAs and letter agreements at a price equal to115% 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, which will commence in 2023. 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, 2022 and 2021, SPL had $551 million and $232 million of accounts receivable—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.

(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 acquired a portion of our limited partner interests in September 2020 through its purchase of a portion of CQP Target Holdco’s equity interests. SPL recorded

accrued liabilities—related party of $6 million and $4 million as of December 31, 2022 and 2021, respectively, with this related party.

(4) 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, 2022 and 2021, we had $177 million and $141 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.

(5) SPLNG has 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 shall grant 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 December 31, 2022 and 2021, we had $17 million and $15 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 and $15 million of other non-current liabilities—affiliate as of December 31, 2022 and 2021, respectively, from these payments received from Cheniere Marketing.

We had $74 million and $67 million due to affiliates as of December 31, 2022 and 2021, 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 lease, 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. Tug Services distributed $12 million, $9 million and $6 million during the years ended December 31, 2022, 2021 and 2020, 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 that are declared to the common unitholders with respect to the 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 27, 2023, we declared a cash distribution of $1.07 per common unit to unitholders of record as of February 6, 2023 and the related general partner distribution that was paid on February 14, 2023. These distributions consist of a base amount of $0.775 per unit and a variable amount of $0.295 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	Subordinated Units	General Partner Units	IDR
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		$ 3.00	$ —		
Year Ended December 31, 2020					
Net income	$ 1,183				
Declared distributions	1,375	1,080	174	27	94
Assumed allocation of undistributed net loss (1)	$ (192)	(155)	(33)	(4)	—
Assumed allocation of net income		$ 925	$ 141	$ 23	$ 94
Weighted average units outstanding		399.3	84.7		
Basic and diluted net income per unit (2)		$ 2.32	$ 1.67		

(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, 2022 and thus are not recognized as liabilities in our Consolidated Financial Statements.

Gas Supply, Transportation and Storage Service Agreements

SPL has a physical natural gas supply contracts to secure natural gas feedstock for the Liquefaction Project. The remaining terms of these contracts range up to 15 years.

Additionally, SPL has natural gas transportation and storage service agreements for the Liquefaction Project. The initial terms of the natural gas transportation agreements range up to 20 years, with renewal options for certain contracts, and commence upon the occurrence of conditions precedent. The initial terms of the SPL natural gas storage service agreements range up to 10 years.

As of December 31, 2022, SPL's obligations under natural gas supply, transportation and storage service agreements for contracts in which conditions precedent 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 Affiliates (1)	Payments Due to Related Parties (1)
2023	$ 6.5	$ 0.1	$ 0.1
2024	4.4	0.1	0.1
2025	3.5	0.1	0.1
2026	2.8	0.1	—
2027	2.5	0.1	—
Thereafter	8.8	0.8	—
Total	$ 28.5	$ 1.3	$ 0.3

(1) Pricing of natural gas supply contracts is variable based on market commodity basis prices adjusted for basis spread, and pricing of our IPM agreement is variable based on global gas market prices less fixed liquefaction fees and certain costs incurred by us. Amounts included are based on estimated forward prices and basis spreads as of December 31, 2022. 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 $0.4 billion under natural gas supply agreements with unsatisfied conditions precedent.

Services and Other Agreements

We have certain fixed commitments under services and other agreements of $1.0 billion with third parties and $1.3 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, 2022, 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 following table shows external customers with revenues of 10% or greater of total revenues from external customers and external customers with trade and other receivables, net of current expected credit losses and contract assets, net of current expected credit losses balances of 10% or greater of total trade and other receivables, net of current expected credit losses from external customers and contract assets, net of current expected credit losses from external customers, respectively:

	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,	
	2022	2021	2020	2022	2021
Customer A	22%	24%	24%	27%	28%
Customer B	15%	17%	18%	18%	17%
Customer C	15%	17%	17%	*	*
Customer D	15%	16%	15%	18%	14%
Customer E	10%	11%	11%	*	12%
Customer F	*	*	*	13%	12%

* 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,		
	2022	2021	2020
United States	$ 5,278	$ 2,872	$ 2,285
India	1,951	1,342	970
South Korea	1,932	1,336	924
Ireland	1,858	1,237	842
United Kingdom	1,026	966	456
Switzerland	593	208	21
Other countries	—	—	7
Total	$ 12,638	$ 7,961	$ 5,505

NOTE 18—SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2022	2021	2020
Cash paid during the period for interest on debt, net of amounts capitalized	$ 777	$ 812	$ 904

The balance in property, plant and equipment, net of accumulated depreciation funded with accounts payable and accrued liabilities (including affiliate) was $273 million, $324 million and $212 million and as of years ended December 31, 2022, 2021 and 2020, respectively.

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 has been 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, 2022, 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

None.

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 other requirements for audit committee members provided for in the listing standards of the NYSE American 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 a “financial expert” and are “financially sophisticated” as such terms are defined by the SEC and the NYSE American, respectively.

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 American, 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, Matthew Runkle and Tim Wyatt 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 17, 2023, regarding the individuals who currently serve on the board of directors and as executive officers of our general partner. The appointments of Messrs. Dell'Amore, Murski and Runkle to the board of directors of our general partner were made pursuant to the rights of Blackstone CQP Holdco LP ("Blackstone CQP Holdco") under the Third Amended and Restated Limited Liability Company Agreement of our general partner 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	60	May 2016	Chairman of the Board and President and Chief Executive Officer
James R. Ball	72	September 2012	Director
Zach Davis	38	August 2020	Director and Executive Vice President and Chief Financial Officer
Corey Grindal	51	September 2022	Director and Executive Vice President and Chief Operating Officer
Christopher Dell'Amore	33	January 2023	Director
Lon McCain	74	March 2007	Director
Mark Murski	47	September 2020	Director
Vincent Pagano, Jr.	72	December 2012	Director
Oliver G. Richard, III	70	September 2012	Director
Matthew Runkle	44	July 2021	Director
Tim Wyatt	42	September 2022	Director and Senior Vice President, Corporate Development and Strategy

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 38 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. 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.

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 until August 2011, he also served as an Executive Director of Gas Strategies Group. 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 City University Business School (now 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, a 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 2023 All-America Executive Team Best CFO in Energy - Natural Gas & Master Limited Partnerships.

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 15 years of energy finance experience, focusing on strategic advisory assignments and financings for companies, projects and assets 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 Atlantia. 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 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. It was determined that Mr. Dell'Amore should serve as a director of our general partner because of his significant energy and infrastructure investment experience.

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.

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.

Mark Murski

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

Mr. Murski is a Managing Partner and Chief Operating Officer in the Americas for Brookfield Infrastructure, where he is responsible for North American infrastructure operations. From 2006 to 2015 he worked for Brookfield's global advisory practice, where he ran the mergers and acquisitions practice. Mr. Murski joined Brookfield in 2003 where he focused on financings, acquisitions and divestitures. Mr. Murski currently serves as a director of City Office REIT Inc., a real estate company focused on office properties in the southern and western United States. Mr. Murski is a Chartered Professional Accountant, a CFA charterholder and is a graduate of the Richard Ivey School of Business. It was determined that Mr. Murski should serve as a director of our general partner because of his significant investment experience with Brookfield Infrastructure.

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.

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 currently serves as a director of American Electric Power Company, Inc., a publicly traded electric utility. 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.

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

Mr. Runkle is a Senior Managing Director in the Infrastructure Group for Blackstone Inc., where he focuses on investments in the renewables, utility and midstream sectors. Since joining Blackstone in October 2017, Mr. Runkle has been involved in the execution of Blackstone investments, including CQP and Tallgrass Energy. Prior to joining Blackstone, Mr. Runkle served as a Principal at ArcLight Capital Partners, LLC from August 2002 to September 2017, where he sourced, executed and managed infrastructure investments across the midstream and renewables sectors. Mr. Runkle also served from July 2000 to July 2002 as an Analyst at the NorthBridge Group, where he provided strategic and management consulting to utility and energy companies. Mr. Runkle currently serves as a director of Tallgrass Energy Partners GP, L.P., a midstream energy infrastructure company. Mr. Runkle holds a Bachelor's degree in Geology and Geophysics from Yale University. It was determined that Mr. Runkle should serve as a director of our general partner because of his significant energy and infrastructure investment experience.

Tim Wyatt
Director and Senior Vice President, Corporate Development and Strategy of our general partner and a member of the CMI SPA Committee

Mr. Wyatt has served as Senior Vice President, Corporate Development and Strategy of Cheniere since March 2021 and Cheniere Partners GP since May 2021. Mr. Wyatt joined Cheniere in April 2011 as Senior Manager, Shipping and Trading (UK) and subsequently served as Vice President, LNG Origination and Trading, before serving as Vice President, Commercial Operations of Cheniere from March 2017 to June 2019 and Cheniere Partners GP from May 2017 to August 2019, and Vice President, Business Development and Strategy of Cheniere from June 2019 to March 2021 and Cheniere Partners GP from August 2019 to May 2021, where he set up the needed systems, procedures and processes for Cheniere to facilitate the delivery of LNG to its long-term customers. Mr. Wyatt has over 15 years of experience in LNG operations, LNG marketing and LNG shipping and trading. Prior to joining Cheniere, Mr. Wyatt was with Simpson, Spence and Young, where he was responsible for the gas business. Prior to Simpson, Spence and Young, Mr. Wyatt held positions with Shell. Mr. Wyatt holds a B.A. Honors from UWE Bristol. It was determined that Mr. Wyatt should serve as a director of our general partner because of his background in the LNG industry. Mr. Wyatt 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.

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 2022 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
James R. Ball
Zach Davis
Corey Grindal
Christopher Dell'Amore
Lon McCain
Mark Murski
Vincent Pagano, Jr.
Oliver G. Richard, III
Matthew Runkle
Tim Wyatt

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 2022.

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. Murski serves as a Managing Partner and Chief Operating Officer in the Americas for Brookfield Infrastructure, Mr. Dell'Amore serves as a Principal in the Infrastructure Group for Blackstone Inc. and Mr. Runkle serves as a Senior Managing Director in the Infrastructure Group for Blackstone Inc. 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 2022 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)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
James R. Ball (3)	115,000	163,980	—	—	—	—	278,980
Eric Bensaude (2)(4)	—	—	—	—	—	—	—
Zach Davis (2)	—	—	—	—	—	—	—
Corey Grindal (2)(4)	—	—	—	—	—	—	—
Adam Kuhnley (4)(5)	—	—	—	—	—	—	—
Lon McCain (6)	105,000	165,660	—	—	—	—	270,660
Mark Murski (5)	—	—	—	—	—	—	—
Vincent Pagano, Jr. (7)	100,000	171,540	—	—	—	—	271,540
Scott Peak (4)	—	—	—	—	—	—	—
Oliver G. Richard, III (8)	87,500	163,980	—	—	—	—	251,480
Matthew Runkle (5)	—	—	—	—	—	—	—
Aaron Stephenson (2)(4)	—	—	—	—	—	—	—
Tim Wyatt (2)(4)	—	—	—	—	—	—	—

(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) Mr. Fusco served as an executive officer of our general partner and as an executive officer of Cheniere during fiscal year 2022. Mr. Bensaude served as an officer of Cheniere Marketing Ltd., a subsidiary of Cheniere during fiscal year 2022. Mr. Davis served as an executive officer of our general partner and as an executive officer of Cheniere during fiscal year 2022. Mr. Grindal served as an officer of our general partner and as an executive officer of Cheniere during fiscal year 2022. Mr. Stephenson served as an officer of our general partner and as an executive officer of Cheniere during fiscal year 2022. Mr. Wyatt served as an officer of our general partner and as an executive officer of Cheniere during fiscal year 2022. 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) Mr. Ball was granted 3,000 phantom units in 2022 with a grant date fair value of $163,980. In addition, Mr. Ball received $102,488 in cash and 1,125 common units on account of 3,000 phantom units granted in earlier years that vested in 2022. As of December 31, 2022, he held 7,500 phantom units and 6,000 common units for a total of 13,500 units.

(4) Effective as of September 23, 2022, Messrs. Grindal and Wyatt were appointed to the board of directors of our general partner and Messrs. Bensaude and Stephenson each resigned as a member of the board of directors of our general partner. Effective as of April 5, 2022, Mr. Kuhnley was appointed to the board of directors of our general partner and Mr. Peak resigned as a member of the board of directors of our general partner.

(5) Mr. Kuhnley is a Managing Director in the Infrastructure Group for Blackstone Inc., Mr. Murski is a Managing Partner and Chief Operating Officer in the Americas for Brookfield Infrastructure and Mr. Runkle is a Senior Managing Director in the Infrastructure Group for Blackstone Inc. They do not receive additional compensation for service as directors.

(6) Mr. McCain was granted 3,000 phantom units in 2022 with a grant date fair value of $165,660. In addition, Mr. McCain received $62,123 in cash and 1,875 common units on account of 3,000 phantom units granted in earlier years that vested in 2022. As of December 31, 2022, he held 7,500 phantom units and 11,625 common units for a total of 19,125 units.

(7) Mr. Pagano was granted 3,000 phantom units in 2022 with a grant date fair value of $171,540. In addition, Mr. Pagano received $85,770 in cash and 1,500 common units on account of 3,000 phantom units granted in earlier years that vested in 2022. As of December 31, 2022, he held 7,500 phantom units and 10,125 common units for a total of 17,625 units.

(8) Mr. Richard was granted 3,000 phantom units in 2022 with a grant date fair value of $163,980. In addition, Mr. Richard received $81,990 in cash and 1,500 common units on account of 3,000 phantom units granted in earlier years that vested in 2022. As of December 31, 2022, he held 7,500 phantom units and 14,250 common units for a total of 21,750 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 17, 2023, 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 700 Milam Street, Suite 1900, 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 17, 2023:

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)	203,784,670	42%	41%
Brookfield Asset Management Inc. (3)	204,321,313	42%	41%

(1) Cheniere Energy, Inc. also owns 9,877,924 of our general partner units.

(2) Information is based on filings of Form 4 with the SEC on October 4, 2021 by CQP Rockies Platform LLC, BIP Chinook Holdco L.L.C. (record holder of 194,216 common units), BIP-V Chinook Holdco II L.L.C. (record holder of 67,939 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 17, 2023, 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 17, 2023, the current directors and executive officers of CQP beneficially owned an aggregate of 49,649 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 17, 2023, 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 17, 2023, Cheniere Energy, Inc. had 244 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	—	—%	724,062	*%
Zach Davis	—	—	94,591	*
Corey Grindal	7,649	*	131,643	*
Tim Wyatt	—	—	60,038	*
James R. Ball	6,000	*	—	—
Christopher Dell'Amore (1)	—	—	—	—
Lon McCain	11,625	*	—	—
Mark Murski (1)	—	—	—	—
Vincent Pagano, Jr.	10,125	*	—	—
Oliver G. Richard, III	14,250	*	—	—
Matthew Runkle (1)	—	—	—	—
All current directors and executive officers as a group (11 persons)	49,649	*%	1,010,334	*%

* Less than 1%

(1) Messrs. Dell'Amore, Murski and Runkle were appointed as directors of our general partner pursuant to the rights of Blackstone CQP Holdco under the Third Amended and Restated Limited Liability Company Agreement of our general partner 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, 2022 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	15,000	N/A	1,182,500
Total	15,000	N/A	1,182,500

(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.

Employment of Director's Family Member

Corey Grindal's son, Christian Grindal, is a non-executive employee of Cheniere who earned aggregate cash compensation of approximately $165,000 for fiscal year 2022, consisting of base salary, cash bonus and certain relocation and associated transportation allowances, in addition to receiving equity compensation consisting of restricted stock unit ("RSU") awards with a grant date fair value of $11,584. Christian Grindal is expected to earn aggregate cash compensation of approximately $140,000 to $150,000 for fiscal year 2023, consisting of base salary, cash bonus and transportation allowances, in addition to receiving equity compensation consisting of RSU awards with an expected intended value of $16,960. In addition, Christian Grindal received in 2022 and is eligible to receive in 2023 other customary employee benefits. The compensation for Christian Grindal was established by Cheniere in accordance with its compensation practices applicable to employees with comparable qualifications and responsibilities and holding similar positions, without the involvement of Corey Grindal.

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 2022 and 2021 (in millions):

	Fiscal 2022	Fiscal 2021
Audit Fees	$ 3	$ 3

Audit Fees—Audit fees for 2022 and 2021 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 2022 and 2021.

Tax Fees—There were no tax fees in 2022 and 2021.

Other Fees—There were no other fees in 2022 and 2021.

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, 2022 and 2021 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.		Incorporated by Reference (1)			
	Description	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	Description of the Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934	CQP	10-K	4.45	2/24/2022
10.1	LNG Terminal Use Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and SPLNG	Cheniere	10-Q	10.1	11/15/2004
10.2	Amendment of LNG Terminal Use Agreement, dated January 24, 2005, by and between Total LNG USA, Inc. and SPLNG	Cheniere	10-K	10.40	3/10/2005
10.3	Amendment of LNG Terminal Use Agreement, dated June 15, 2010, by and between Total Gas & Power North America, Inc. and SPLNG	Cheniere	10-Q	10.2	8/6/2010
10.4	Omnibus Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and SPLNG	Cheniere	10-Q	10.2	11/15/2004
10.5	Parent Guarantee, dated as of November 5, 2004, by Total S.A. in favor of SPLNG	Cheniere	10-Q	10.3	11/15/2004
10.6	Letter Agreement, dated September 11, 2012, between Total Gas & Power North America, Inc. and SPLNG	CQP	10-Q	10.1	11/2/2012
10.7	LNG Terminal Use Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and SPLNG	Cheniere	10-Q	10.4	11/15/2004
10.8	Amendment to LNG Terminal Use Agreement, dated December 1, 2005, by and between Chevron U.S.A. Inc. and SPLNG	SPLNG	S-4	10.28	11/22/2006
10.9	Amendment of LNG Terminal Use Agreement, dated June 16, 2010, by and between Chevron U.S.A. Inc. and SPLNG	Cheniere	10-Q	10.3	8/6/2010
10.10	Omnibus Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and SPLNG	Cheniere	10-Q	10.5	11/15/2004
10.11	Guaranty Agreement, dated as of December 15, 2004, from ChevronTexaco Corporation to SPLNG	SPLNG	S-4	10.12	11/22/2006
10.12	Second Amended and Restated LNG Terminal Use Agreement, dated as of July 31, 2012, between SPL and SPLNG	SPLNG	8-K	10.1	8/6/2012
10.13	Letter Agreement, dated May 28, 2013, by and between SPL and SPLNG	SPLNG	10-Q	10.1	8/2/2013
10.14	Guarantee Agreement, dated as of July 31, 2012, by the Partnership in favor of SPLNG	SPLNG	8-K	10.2	8/6/2012
10.15	Third 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	CQP	8-K	10.2	3/23/2020
10.16	Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, among SPL, as borrower, certain subsidiaries of SPL, 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	CQP	8-K	10.1	3/23/2020
10.17	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	CQP	8-K	10.3	3/23/2020

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.18	First Amendment to Third Amended and Restated Common Terms Agreement, dated as of July 26, 2021, 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	CQP	10-Q	10.2	11/4/2021
10.19	Credit and Guaranty Agreement, dated May 29, 2019, among the Partnership, as Borrower, certain subsidiaries of the Partnership, as Subsidiary Guarantors, the lenders from time to time party thereto, Natixis, Société Générale, The Bank of Nova Scotia, Wells Fargo Bank, as Issuing Banks, MUFG Bank, LTD as Administrative Agent and Sole Coordinating Lead Arranger, and certain arrangers and other participants	CQP	8-K	10.1	6/3/2019
10.20	Consent and Amendment to the Credit and Guaranty Agreement, dated July 6, 2022, among the Partnership, as Borrower, certain subsidiaries of the Partnership, as Subsidiary Guarantors, the lenders from time to time party thereto, Natixis, Société Générale, The Bank of Nova Scotia, Wells Fargo Bank, as Issuing Banks, MUFG Bank, LTD as Administrative Agent and Sole Coordinating Lead Arranger, and certain arrangers and other participants	CQP	10-Q	10.1	8/4/2022
10.21	Registration Rights Agreement, dated as of November 29, 2022, between SPL and Goldman Sachs & Co. LLC	SPL	8-K	10.1	11/29/2022
10.22†	Cheniere Energy Partners, L.P. 2007 Long-Term Incentive Plan	CQP	8-K	10.3	3/26/2007
10.23†	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
10.24†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan	CQP	10-Q	10.8	11/2/2012
10.25†	Form of Amendment to Phantom Units Agreement	CQP	10-Q	10.7	11/2/2012
10.26†	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
10.27†	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
10.28†	Form of Indemnification Agreement for officers and/or directors of Cheniere Partners GP	CQP	10-Q	10.2	11/3/2022
10.29	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
10.30	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
10.31	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 (iv) 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
10.32	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
10.33	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (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
10.34	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-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
10.35	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-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
10.36	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between 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
10.37	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
10.38	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-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
10.39	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
10.40	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-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
10.41	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-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
10.42	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-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
10.43	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-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
10.44*	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-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				
10.45	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
10.46	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
10.47	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
10.48	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
10.49	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
10.50	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
10.51	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
10.52	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
10.53	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
10.54	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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.55	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
10.56	Letter Agreement, dated December 9, 2020, 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	12/9/2020
10.57	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
10.58	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	10.3	8/5/2021
10.59	Letter agreement, dated November 3, 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	10.3	11/4/2021
10.60	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
10.61	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
10.62	Management Services Agreement, dated May 14, 2012, by and between Cheniere Terminals and SPL	CQP	8-K	10.6	5/15/2012
10.63	Amendment to Management Services Agreement, dated September 28, 2015, between Cheniere Terminals and SPL	SPL	10-Q/A	10.8	11/9/2015
10.64	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
10.65	Management Services Agreement, dated May 27, 2013, by and between Cheniere Terminals and CTPL	CQP	10-Q	10.2	8/2/2013
10.66	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
10.67	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
10.68	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
10.69	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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.70	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
10.71	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
10.72	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
10.73	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
10.74	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
10.75	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
10.76	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
10.77	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				
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				
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				

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
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,		
	2022	2021	2020
Operating costs and expenses			
General and administrative expense	$ (4)	$ (3)	$ (3)
General and administrative expense—affiliate	(15)	(14)	(14)
Amortization of capitalized interest associated to investment in subsidiaries	(3)	(3)	(3)
Total operating costs and expenses	(22)	(20)	(20)
Other income (expense)			
Interest expense, net of capitalized interest	(176)	(199)	(217)
Loss on modification or extinguishment of debt	—	(97)	—
Other income	14	1	7
Equity income of affiliates	2,682	1,946	1,413
Total other income	2,520	1,651	1,203
Net income	$ 2,498	$ 1,631	$ 1,183

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

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED BALANCE SHEETS

(in millions)

	December 31, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	$ 899	$ 874
Other current assets	1	1
Total current assets	900	875
Capitalized interest associated to investment in subsidiaries, net of amortization	75	77
Debt issuance costs, net of accumulated amortization	3	5
Investment in affiliates	1,106	3,966
Total assets	$ 2,084	$ 4,923
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accrued liabilities	$ 53	$ 47
Due to affiliates	3	3
Total current liabilities	56	50
Long-term debt, net of debt issuance costs	4,159	4,154
Partners' equity	(2,131)	719
Total liabilities and partners' equity	$ 2,084	$ 4,923

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

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SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED STATEMENTS OF CASH FLOWS

(in millions)

	Year Ended December 31,		
	2022	2021	2020
Cash flows provided by operating activities	$ 2,514	$ 1,732	$ 1,190
Cash flows from investing activities			
Capitalized interest associated to investment in subsidiaries	(1)	(1)	(3)
Investments in subsidiaries	(454)	(1,009)	(689)
Distributions received from affiliates	601	403	291
Net cash provided by (used in) investing activities	146	(607)	(401)
Cash flows from financing activities			
Proceeds from issuance of debt	—	2,700	—
Redemptions and repayments of debt	—	(2,600)	—
Debt issuance and other financing costs	—	(35)	—
Debt extinguishment costs	—	(73)	—
Distributions to owners	(2,635)	(1,451)	(1,359)
Net cash used in financing activities	(2,635)	(1,459)	(1,359)
Net increase (decrease) in cash, cash equivalents	25	(334)	(570)
Cash, cash equivalents—beginning of period	874	1,208	1,778
Cash and cash equivalents—end of period	$ 899	$ 874	$ 1,208

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 affiliates are presented at the net amount attributable to CQP. Under this method, the assets and liabilities of affiliates are not consolidated. The investments in net assets of the affiliates are recorded on the Condensed Balance Sheets. The gain from operations of the affiliates is reported on a net basis as equity income of affiliates.

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

NOTE 2—DEBT

Our debt consisted of the following (in millions):

	December 31,	
	2022	2021
Senior Secured 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
Total CQP Senior Notes	4,200	4,200
CQP Credit Facilities executed in 2019	—	—
Total debt	4,200	4,200
Unamortized debt issuance costs	(41)	(46)
Total long-term debt, net of premium and debt issuance costs	$ 4,159	$ 4,154

Below is a schedule of future principal payments that we are obligated to make on our outstanding debt at December 31, 2022 (in millions):

Years Ending December 31,	Principal Payments
2023	$ —
2024	—
2025	—
2026	—
2027	—
Thereafter	4,200
Total	$ 4,200

NOTE 3—SUPPLEMENTAL CASH FLOW INFORMATION

The following table provides supplemental disclosure of cash flow information, excluding any contributions to the parent that were immediately contributed to the subsidiaries (in millions):

	Year Ended December 31,		
	2022	2021	2020
Cash paid during the period for interest, net of amounts capitalized	$ 163	$ 197	$ 213
Non-cash capital distributions (1)	2,682	1,946	1,413

(1) Amounts represent equity income of affiliates.

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 22, 2023

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 22, 2023
/s/ Zach Davis Zach Davis	Executive Vice President and Chief Financial Officer, Director (Principal Financial Officer)	February 22, 2023
/s/ David Slack David Slack	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 22, 2023
/s/ Corey Grindal Corey Grindal	Executive Vice President and Chief Operating Officer, Director	February 22, 2023
/s/ Tim Wyatt Tim Wyatt	Senior Vice President, Corporate Development and Strategy, Director	February 22, 2023
/s/ James R. Ball James R. Ball	Director	February 22, 2023
/s/ Christopher Dell'Amore Christopher Dell'Amore	Director	February 22, 2023
/s/ Lon McCain Lon McCain	Director	February 22, 2023
/s/ Mark Murski Mark Murski	Director	February 22, 2023
/s/ Vincent Pagano Jr. Vincent Pagano Jr.	Director	February 22, 2023
/s/ Oliver G. Richard, III Oliver G. Richard, III	Director	February 22, 2023
/s/ Matthew Runkle Matthew Runkle	Director	February 22, 2023

Exhibit 10.44

CHANGE ORDER

80-ACRES BRIDGE

PROJECT NAME: Sabine Pass LNG Stage 4 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00070

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: 28-Oct-2022

CONTRACTOR: Bechtel Oil, Gas and Chemicals, Inc.

DATE OF AGREEMENT: November 7, 2018

The Agreement between the Parties listed above is changed as follows:

1. In accordance with Section 6.1 of the Agreement (*Change Orders Requested by Owner*), the Parties agree this Change Order includes Contractor's costs to provide the Engineering, Procurement, and Construction services to install a permanent beam bridge ("80 Acres Bridge") between the 80 Acres real estate and Lighthouse Road. This Change Order comprises:
   a. A concrete slab beam design with 12ea concrete beams; and
   b. Includes for the demolition and removal of the existing north and south bridges.

2. For context this Change Order, therefore, addresses Work that Contractor commenced and subsequently discontinued under Change Orders CO-00047 and CO-00054, executed on 18-Jun-2021 and 01-Dec-2021 respectively.

3. The detailed cost breakdown for this Change Order is detailed in Exhibit A of this Change Order.

4. Schedule C-3 (Milestone Payment Schedule) of Attachment C of the Agreement will be amended by including the milestone(s) listed in Exhibit B of this Change Order.

Adjustment to Contract Price Applicable to Subproject 6(a)

1. The original Contract Price Applicable to Subproject 6(a) was	$	2,016,892,573
2. Net change for Contract Price Applicable to Subproject 6(a) by previously authorized Change Orders (#01-08, 10-13, 15, 17-18, 21-22, 24, 28-29, 31-32, 34-35, 38, 41-42, 45-49, 51, 53-58, 61)	$	697,987
3. The Contract Price Applicable to Subproject 6(a) prior to this Change Order was	$	2,017,590,560
4. The Contract Price Applicable to Subproject 6(a) will be unchanged by this Change Order in the amount of	$	—
5. The Provisional Sum Applicable to Subproject 6(a) will be unchanged by this Change Order in the amount of	$	—
6. The Contract Price Applicable to Subproject 6(a) including this Change Order will be	$	2,017,590,560

Adjustment to Contract Price Applicable to Subproject 6(b)

7. The original Contract Price Applicable to Subproject 6(b) (in CO-00009) was	$	457,696,000
8. Net change for Contract Price Applicable to Subproject 6(b) by previously authorized Change Orders (#14, 16, 19-20, 23, 25-27, 30-31, 33, 36-37, 39-40, 43-44, 50, 52, 59-60, 62-69)	$	7,578,450
9. The Contract Price Applicable to Subproject 6(b) prior to this Change Order was	$	465,274,450
10. The Contract Price Applicable to Subproject 6(b) will be changed by this Change Order	$	1,584,805
11. The Provisional Sum Applicable to Subproject 6(b) will be unchanged by this Change Order	$	—
12. The Contract Price Applicable to Subproject 6(b) including this Change Order will be	$	466,859,255

Adjustment to Contract Price

13. The original Contract Price for Subproject 6(a) and Subproject 6(b) was (add lines 1 and 7)	$	2,474,588,573
14. The Contract Price prior to this Change Order was (add lines 3 and 9)	$	2,482,865,010

15. The Contract Price will be increased by this Change Order in the amount of (add lines 4, 5, 10 and 11)	$	1,584,805
16. The new Contract Price including this Change Order will be (add lines 14 and 15)	$	2,484,449,815

Adjustment to dates in Project Schedule for Subproject 6(a)

The following dates are modified: N/A

Adjustment to other Changed Criteria for Subproject 6(a): N/A

Adjustment to Payment Schedule for Subproject 6(a): N/A

Adjustment to Minimum Acceptance Criteria for Subproject 6(a): N/A

Adjustment to Performance Guarantees for Subproject 6(a): N/A

Adjustment to Design Basis for Subproject 6(a): N/A

Other adjustments to liability or obligations of Contractor or Owner under the Agreement for Subproject 6(a): N/A

Adjustment to dates in Project Schedule for Subproject 6(b)

The following dates are modified: **N/A – This Work is performed post-Substantial Completion**

Adjustment to other Changed Criteria for Subproject 6(b): **N/A – This Work is performed post-Substantial Completion**

Adjustment to Payment Schedule for Subproject 6(b): **Yes; see Exhibit B**

Adjustment to Design Basis for Subproject 6(b): **N/A - This Work is performed post-Substantial Completion**

Other adjustments to liability or obligation of Contractor or Owner under the Agreement: **N/A - This Work is performed post-Substantial Completion**

Select either A or B:

[A] This Change Order **shall** constitute a full and final settlement and accord and satisfaction of all effects of the change reflected in this Change Order upon the Changed Criteria and **shall** be deemed to compensate Contractor fully for such change. Initials: /s/ SS Contractor /s/ DC Owner

~~[B] This Change Order **shall not** constitute a full and final settlement and accord and satisfaction of all effects of the change reflected in this Change Order upon the Changed Criteria and **shall not** be deemed to compensate Contractor fully for such change. Initials: ____ Contractor ____ Owner~~

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

/s/ David Craft	/s/ Steve Smith
Owner	Contractor
David Craft	Steve Smith
Name	Name
SVP E&C	Senior Project Manager & Principal Vice President
Title	Title
November 18, 2022	
Date of Signing	Date of Signing

CHANGE ORDER

MOORING SYSTEM LOW-TENSION COMMON ALARM

PROJECT NAME: Sabine Pass LNG Stage 4 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00071

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: 31-Oct-2022

CONTRACTOR: Bechtel Oil, Gas and Chemicals, Inc.

DATE OF AGREEMENT: November 7, 2018

The Agreement between the Parties listed above is changed as follows:

1. In accordance with Section 6.1 of the Agreement (*Change Orders Requested by Owner*), the Parties agree this Change Order includes Contractor's costs to provide the Procurement and Construction services to add a Low-Tension Common Alarm to the East, West and Third Berth jetties' mooring systems.

2. The detailed cost breakdown for this Change Order is detailed in Exhibit A of this Change Order.

3. Schedule C-3 (Milestone Payment Schedule) of Attachment C of the Agreement will be amended by including the milestone(s) listed in Exhibit B of this Change Order.

Adjustment to Contract Price Applicable to Subproject 6(a)

1. The original Contract Price Applicable to Subproject 6(a) was	$	2,016,892,573
2. Net change for Contract Price Applicable to Subproject 6(a) by previously authorized Change Orders (#01-08, 10-13, 15, 17-18, 21-22, 24, 28-29, 31-32, 34-35, 38, 41-42, 45-49, 51, 53-58, 61, 68)	$	697,987
3. The Contract Price Applicable to Subproject 6(a) prior to this Change Order was	$	2,017,590,560
4. The Contract Price Applicable to Subproject 6(a) will be unchanged by this Change Order in the amount of	$	—
5. The Provisional Sum Applicable to Subproject 6(a) will be unchanged by this Change Order in the amount of	$	—
6. The Contract Price Applicable to Subproject 6(a) including this Change Order will be	$	2,017,590,560

Adjustment to Contract Price Applicable to Subproject 6(b)

7. The original Contract Price Applicable to Subproject 6(b) (in CO-00009) was	$	457,696,000
8. Net change for Contract Price Applicable to Subproject 6(b) by previously authorized Change Orders (#14, 16, 19-20, 23, 25-27, 30-31, 33, 36-37, 39-40, 43-44, 50, 52, 59-60, 62-70)	$	9,163,255
9. The Contract Price Applicable to Subproject 6(b) prior to this Change Order was	$	466,859,255
10. The Contract Price Applicable to Subproject 6(b) will be unchanged by this Change Order	$	71,174
11. The Provisional Sum Applicable to Subproject 6(b) will be changed by this Change Order	$	—
12. The Contract Price Applicable to Subproject 6(b) including this Change Order will be	$	466,930,429

Adjustment to Contract Price

13. The original Contract Price for Subproject 6(a) and Subproject 6(b) was (add lines 1 and 7)	$	2,474,588,573
14. The Contract Price prior to this Change Order was (add lines 3 and 9)	$	2,484,449,815
15. The Contract Price will be increased by this Change Order in the amount of (add lines 4, 5, 10 and 11)	$	71,174
16. The new Contract Price including this Change Order will be (add lines 14 and 15)	$	2,484,520,989

Adjustment to dates in Project Schedule for Subproject 6(a)

The following dates are modified: N/A

Adjustment to other Changed Criteria for Subproject 6(a): N/A

Adjustment to Payment Schedule for Subproject 6(a): N/A

Adjustment to Minimum Acceptance Criteria for Subproject 6(a): N/A

Adjustment to Performance Guarantees for Subproject 6(a): N/A

Adjustment to Design Basis for Subproject 6(a): N/A

Other adjustments to liability or obligations of Contractor or Owner under the Agreement for Subproject 6(a): N/A

Adjustment to dates in Project Schedule for Subproject 6(b)

The following dates are modified: **N/A – This Work is performed post-Substantial Completion**

Adjustment to other Changed Criteria for Subproject 6(b): **N/A – This Work is performed post-Substantial Completion**

Adjustment to Payment Schedule for Subproject 6(b): **Yes; see Exhibit B**

Adjustment to Design Basis for Subproject 6(b): **N/A – This Work is performed post-Substantial Completion**

Other adjustments to liability or obligation of Contractor or Owner under the Agreement: **N/A – This Work is performed post-Substantial Completion**

Select either A or B:

[A] This Change Order **shall** constitute a full and final settlement and accord and satisfaction of all effects of the change reflected in this Change Order upon the Changed Criteria and **shall** be deemed to compensate Contractor fully for such change. Initials: /s/ SS Contractor /s/ DC Owner

~~[B] This Change Order **shall not** constitute a full and final settlement and accord and satisfaction of all effects of the change reflected in this Change Order upon the Changed Criteria and **shall not** be deemed to compensate Contractor fully for such change. Initials: ____ Contractor ____ Owner~~

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

/s/ David Craft	/s/ Steve Smith
Owner	Contractor
David Craft	Steve Smith
Name	Name
SVP E&C	Senior Project Manager & Principal Vice President
Title	Title
November 18, 2022	
Date of Signing	Date of Signing

CHANGE ORDER

FERC HYDROCARBON PERMIT CONDITIONS

PROJECT NAME: Sabine Pass LNG Stage 4 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00072

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: 31-Oct-2022

CONTRACTOR: Bechtel Oil, Gas and Chemicals, Inc.

DATE OF AGREEMENT: November 7, 2018

The Agreement between the Parties listed above is changed as follows:

1. In accordance with Section 6.1 of the Agreement (*Change Orders Requested by Owner*), and as per the requirements stated in Owner correspondence SPL4-BE-C22-023 dated 02-Sep-2022, the Parties agree this Change Order includes Contractor's costs to provide the Engineering, Procurement, and Construction services for:
   a. A passive system designed to withstand a 20-minute fire exposure per UL 1709 for instrumented valves in Subproject 6(b) which activate emergency systems under Condition 79 and associated conditions;
   b. Flame detection covering a minimum of 90% of all areas by two or more detectors that contain flammable or combustible fluids, including the entire length of the marine transfer piping and valve platform, under Condition 64 and associated conditions;
   c. Replacement of sodium bicarbonate extinguishers with potassium bicarbonate extinguishers in areas where LNG is handled under Condition 73 and associated conditions; and
   d. Firewater hydrants or monitors for the entire length of the marine transfer piping, under Condition 80 and associated conditions.

2. The detailed cost breakdown for this Change Order is detailed in Exhibit A of this Change Order.

3. Schedule C-3 (Milestone Payment Schedule) of Attachment C of the Agreement will be amended by including the milestone(s) listed in Exhibit B of this Change Order.

Adjustment to Contract Price Applicable to Subproject 6(a)		
1. The original Contract Price Applicable to Subproject 6(a) was	$	2,016,892,573
2. Net change for Contract Price Applicable to Subproject 6(a) by previously authorized Change Orders (#01-08, 10-13, 15, 17-18, 21-22, 24, 28-29, 31-32, 34-35, 38, 41-42, 45-49, 51, 53-58, 61, 68)	$	697,987
3. The Contract Price Applicable to Subproject 6(a) prior to this Change Order was	$	2,017,590,560
4. The Contract Price Applicable to Subproject 6(a) will be unchanged by this Change Order in the amount of	$	—
5. The Provisional Sum Applicable to Subproject 6(a) will be unchanged by this Change Order in the amount of	$	—
6. The Contract Price Applicable to Subproject 6(a) including this Change Order will be	$	2,017,590,560
Adjustment to Contract Price Applicable to Subproject 6(b)		
7. The original Contract Price Applicable to Subproject 6(b) (in CO-00009) was	$	457,696,000
8. Net change for Contract Price Applicable to Subproject 6(b) by previously authorized Change Orders (#14, 16, 19-20, 23, 25-27, 30-31, 33, 36-37, 39-40, 43-44, 50, 52, 59-60, 62-71)	$	9,234,429
9. The Contract Price Applicable to Subproject 6(b) prior to this Change Order was	$	466,930,429
10. The Contract Price Applicable to Subproject 6(b) will be changed by this Change Order	$	1,308,101
11. The Provisional Sum Applicable to Subproject 6(b) will be unchanged by this Change Order	$	—
12. The Contract Price Applicable to Subproject 6(b) including this Change Order will be	$	468,238,530
Adjustment to Contract Price		
13. The original Contract Price for Subproject 6(a) and Subproject 6(b) was (add lines 1 and 7)	$	2,474,588,573
14. The Contract Price prior to this Change Order was (add lines 3 and 9)	$	2,484,520,989

15. The Contract Price will be increased by this Change Order in the amount of (add lines 4, 5, 10 and 11)	$	1,308,101
16. The new Contract Price including this Change Order will be (add lines 14 and 15)	$	2,485,829,090

Adjustment to dates in Project Schedule for Subproject 6(a)

The following dates are modified: N/A

Adjustment to other Changed Criteria for Subproject 6(a): N/A

Adjustment to Payment Schedule for Subproject 6(a): N/A

Adjustment to Minimum Acceptance Criteria for Subproject 6(a): N/A

Adjustment to Performance Guarantees for Subproject 6(a): N/A

Adjustment to Design Basis for Subproject 6(a): N/A

Other adjustments to liability or obligations of Contractor or Owner under the Agreement for Subproject 6(a): N/A

Adjustment to dates in Project Schedule for Subproject 6(b)

The following dates are modified: **N/A - This Work is performed post-Substantial Completion**

Adjustment to other Changed Criteria for Subproject 6(b): **N/A - This Work is performed post-Substantial Completion**

Adjustment to Payment Schedule for Subproject 6(b): **Yes; see Exhibit B**

Adjustment to Design Basis for Subproject 6(b): **N/A - This Work is performed post-Substantial Completion**

Other adjustments to liability or obligation of Contractor or Owner under the Agreement: **N/A - This Work is performed post-Substantial Completion**

Select either A *or B*:

[A] This Change Order shall constitute a full and final settlement and accord and satisfaction of all effects of the change reflected in this Change Order upon the Changed Criteria and shall be deemed to compensate Contractor fully for such change. Initials: _SS_ Contractor ___ Owner

~~[B] This Change Order **shall not** constitute a full and final settlement and accord and satisfaction of all effects of the change reflected in this Change Order upon the Changed Criteria and **shall not** be deemed to compensate Contractor fully for such change. Initials: Contractor Owner~~

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

/s/ David Craft	/s/ Steve Smith
Owner	Contractor
David Craft	Steve Smith
Name	Name
SVP E&C	Senior Project Manager & Principal Vice President
Title	Title
November 18, 2022	
Date of Signing	Date of Signing

CHANGE ORDER

BN#2 BEACON PILE RELOCATION

PROJECT NAME: Sabine Pass LNG Stage 4 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00073

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: 31-Oct-2022

CONTRACTOR: Bechtel Oil, Gas and Chemicals, Inc.

DATE OF AGREEMENT: November 7, 2018

The Agreement between the Parties listed above is changed as follows:

1. In accordance with Section 6.1 of the Agreement (*Change Orders Requested by Owner*), the Parties agree this Change Order includes Contractor's costs to relocate the Third Berth's Beacon Pile BN#2 to an adjacent location in accordance with direction from the Sabine Bank Pilots Association. Refer to Attachment 1 of this Change Order.

2. The detailed cost breakdown for this Change Order is detailed in Exhibit A of this Change Order.

3. Schedule C-3 (Milestone Payment Schedule) of Attachment C of the Agreement will be amended by including the milestone(s) listed in Exhibit B of this Change Order.

Adjustment to Contract Price Applicable to Subproject 6(a)		
1. The original Contract Price Applicable to Subproject 6(a) was	$	2,016,892,573
2. Net change for Contract Price Applicable to Subproject 6(a) by previously authorized Change Orders (#01-08, 10-13, 15, 17-18, 21-22, 24, 28-29, 31-32, 34-35, 38, 41-42, 45-49, 51, 53-58, 61, 68)	$	697,987
3. The Contract Price Applicable to Subproject 6(a) prior to this Change Order was	$	2,017,590,560
4. The Contract Price Applicable to Subproject 6(a) will be unchanged by this Change Order in the amount of	$	—
5. The Provisional Sum Applicable to Subproject 6(a) will be unchanged by this Change Order in the amount of	$	—
6. The Contract Price Applicable to Subproject 6(a) including this Change Order will be	$	2,017,590,560
Adjustment to Contract Price Applicable to Subproject 6(b)		
7. The original Contract Price Applicable to Subproject 6(b) (in CO-00009) was	$	457,696,000
8. Net change for Contract Price Applicable to Subproject 6(b) by previously authorized Change Orders (#14, 16, 19-20, 23, 25-27, 30-31, 33, 36-37, 39-40, 43-44, 50, 52, 59-60, 62-72)	$	10,542,530
9. The Contract Price Applicable to Subproject 6(b) prior to this Change Order was	$	468,238,530
10. The Contract Price Applicable to Subproject 6(b) will be changed by this Change Order	$	53,097
11. The Provisional Sum Applicable to Subproject 6(b) will be unchanged by this Change Order	$	—
12. The Contract Price Applicable to Subproject 6(b) including this Change Order will be	$	468,291,627
Adjustment to Contract Price		
13. The original Contract Price for Subproject 6(a) and Subproject 6(b) was (add lines 1 and 7)	$	2,474,588,573
14. The Contract Price prior to this Change Order was (add lines 3 and 9)	$	2,485,829,090
15. The Contract Price will be increased by this Change Order in the amount of (add lines 4, 5, 10 and 11)	$	53,097
16. The new Contract Price including this Change Order will be (add lines 14 and 15)	$	2,485,882,187

Adjustment to dates in Project Schedule for Subproject 6(a)

The following dates are modified: N/A

Adjustment to other Changed Criteria for Subproject 6(a): N/A

Adjustment to Payment Schedule for Subproject 6(a): N/A

Adjustment to Minimum Acceptance Criteria for Subproject 6(a): N/A

Adjustment to Performance Guarantees for Subproject 6(a): N/A

Adjustment to Design Basis for Subproject 6(a): N/A

Other adjustments to liability or obligations of Contractor or Owner under the Agreement for Subproject 6(a): N/A

Adjustment to dates in Project Schedule for Subproject 6(b)

The following dates are modified: **N/A**

Adjustment to other Changed Criteria for Subproject 6(b): **N/A**

Adjustment to Payment Schedule for Subproject 6(b): **Yes; see Exhibit B**

Adjustment to Design Basis for Subproject 6(b): **N/A**

Other adjustments to liability or obligation of Contractor or Owner under the Agreement: **N/A**

Select either A *or B*:

[A] This Change Order shall constitute a full and final settlement and accord and satisfaction of all effects of the change reflected in this Change Order upon the Changed Criteria and shall be deemed to compensate Contractor fully for such change. Initials: /s/ SS Contractor /s/ DC Owner

~~[B] This Change Order **shall not** constitute a full and final settlement and accord and satisfaction of all effects of the change reflected in this Change Order upon the Changed Criteria and **shall not** be deemed to compensate Contractor fully for such change. Initials: Contractor Owner~~

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

/s/ David Craft	/s/ Steve Smith
Owner	Contractor
David Craft	Steve Smith
Name	Name
SVP E&C	Senior Project Manager & Principal Vice President
Title	Title
November 18, 2022	
Date of Signing	Date of Signing

CHANGE ORDER

FERC CONDITION 56: ISA 84 GAS DETECTION

PROJECT NAME: Sabine Pass LNG Stage 4 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00074

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: 31-Oct-2022

CONTRACTOR: Bechtel Oil, Gas and Chemicals, Inc.

DATE OF AGREEMENT: November 7, 2018

The Agreement between the Parties listed above is changed as follows:

1. In accordance with Section 6.1 of the Agreement (*Change Orders Requested by Owner*), the Parties agree this Change Order includes Contractor's costs to provide the Engineering, Procurement, and Construction services to comply with FERC Condition 56 referred in Aconex transmittal SPL4-E-EM-TRM-00217 ("Societal Risk from LNG Spills on Water"), that is, installing 11ea gas detectors to justify the 10-minute release duration assumed in the Quantitative Risk Assessment that was performed to address Condition 56.

2. The detailed cost breakdown for this Change Order is detailed in Exhibit A of this Change Order.

3. Schedule C-3 (Milestone Payment Schedule) of Attachment C of the Agreement will be amended by including the milestone(s) listed in Exhibit B of this Change Order.

Adjustment to Contract Price Applicable to Subproject 6(a)

1. The original Contract Price Applicable to Subproject 6(a) was	$	2,016,892,573
2. Net change for Contract Price Applicable to Subproject 6(a) by previously authorized Change Orders (#01-08, 10-13, 15, 17-18, 21-22, 24, 28-29, 31-32, 34-35, 38, 41-42, 45-49, 51, 53-58, 61, 68)	$	697,987
3. The Contract Price Applicable to Subproject 6(a) prior to this Change Order was	$	2,017,590,560
4. The Contract Price Applicable to Subproject 6(a) will be unchanged by this Change Order in the amount of	$	—
5. The Provisional Sum Applicable to Subproject 6(a) will be unchanged by this Change Order in the amount of	$	—
6. The Contract Price Applicable to Subproject 6(a) including this Change Order will be	$	2,017,590,560

Adjustment to Contract Price Applicable to Subproject 6(b)

7. The original Contract Price Applicable to Subproject 6(b) (in CO-00009) was	$	457,696,000
8. Net change for Contract Price Applicable to Subproject 6(b) by previously authorized Change Orders (#14, 16, 19-20, 23, 25-27, 30-31, 33, 36-37, 39-40, 43-44, 50, 52, 59-60, 62-73)	$	10,595,627
9. The Contract Price Applicable to Subproject 6(b) prior to this Change Order was	$	468,291,627
10. The Contract Price Applicable to Subproject 6(b) will be changed by this Change Order	$	443,977
11. The Provisional Sum Applicable to Subproject 6(b) will be unchanged by this Change Order	$	—
12. The Contract Price Applicable to Subproject 6(b) including this Change Order will be	$	468,735,604

Adjustment to Contract Price

13. The original Contract Price for Subproject 6(a) and Subproject 6(b) was (add lines 1 and 7)	$	2,474,588,573
14. The Contract Price prior to this Change Order was (add lines 3 and 9)	$	2,485,882,187
15. The Contract Price will be increased by this Change Order in the amount of (add lines 4, 5, 10 and 11)	$	443,977
16. The new Contract Price including this Change Order will be (add lines 14 and 15)	$	2,486,326,164

Adjustment to dates in Project Schedule for Subproject 6(a)

The following dates are modified: N/A

Adjustment to other Changed Criteria for Subproject 6(a): N/A

Adjustment to Payment Schedule for Subproject 6(a): N/A

Adjustment to Minimum Acceptance Criteria for Subproject 6(a): N/A

Adjustment to Performance Guarantees for Subproject 6(a): N/A

Adjustment to Design Basis for Subproject 6(a): N/A

Other adjustments to liability or obligations of Contractor or Owner under the Agreement for Subproject 6(a): N/A

Adjustment to dates in Project Schedule for Subproject 6(b)

The following dates are modified: N/A

Adjustment to other Changed Criteria for Subproject 6(b): N/A

Adjustment to Payment Schedule for Subproject 6(b): **Yes; see Exhibit B**

Adjustment to Design Basis for Subproject 6(b): N/A

Other adjustments to liability or obligation of Contractor or Owner under the Agreement: N/A

Select either A or B:

[A] This Change Order **shall** constitute a full and final settlement and accord and satisfaction of all effects of the change reflected in this Change Order upon the Changed Criteria and **shall** be deemed to compensate Contractor fully for such change. Initials: /s/ SS Contractor /s/ DC Owner

~~[B] This Change Order **shall not** constitute a full and final settlement and accord and satisfaction of all effects of the change reflected in this Change Order upon the Changed Criteria and **shall not** be deemed to compensate Contractor fully for such change. Initials: ____ Contractor ____ Owner~~

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

/s/ David Craft	/s/ Steve Smith
Owner	Contractor
David Craft	Steve Smith
Name	Name
SVP E&C	Senior Project Manager & Principal Vice President
Title	Title
November 18, 2022	
Date of Signing	Date of Signing

Exhibit 21.1

Subsidiaries of the Registrant as of December 31, 2022

Entity Name	Jurisdiction of Incorporation
Cheniere Creole Trail Pipeline, L.P.	Delaware
Cheniere Energy Investments, LLC	Delaware
Cheniere Pipeline GP Interests, LLC	Delaware
Sabine Pass Liquefaction, LLC	Delaware
Sabine Pass LNG-GP, LLC	Delaware
Sabine Pass LNG-LP, LLC	Delaware
Sabine Pass LNG, L.P.	Delaware
Sabine Pass Tug Services, LLC	Delaware

Exhibit 22.1

Cheniere Energy Partners, L.P.
List of Issuers and Guarantor Subsidiaries

The following entities are guarantors of the 4.500% Senior Notes due 2029, 4.000% Senior Notes due 2031 and 3.250% Senior Notes due 2032 issued by Cheniere Energy Partners, L.P.

Entity	Jurisdiction of Organization	Role
Cheniere Energy Partners, L.P.	Delaware	Issuer
Cheniere Energy Investments, LLC	Delaware	Guarantor
Sabine Pass LNG-GP, LLC	Delaware	Guarantor
Sabine Pass LNG, L.P.	Delaware	Guarantor
Sabine Pass Tug Services, LLC	Delaware	Guarantor
Cheniere Pipeline GP Interests, LLC	Delaware	Guarantor
Cheniere Creole Trail Pipeline, L.P.	Delaware	Guarantor

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the registration statements (No. 333-151155) on Form S-8 and (Nos. 333-220017 and 333-219268) on Form S-3 of our reports dated February 22, 2023, with respect to the consolidated financial statements of Cheniere Energy Partners, L.P. and the effectiveness of internal control over financial reporting.

/s/ KPMG LLP
KPMG LLP

Houston, Texas
February 22, 2023

Exhibit 31.1

CERTIFICATION BY CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13a-14(a) AND 15d-14(a) UNDER THE EXCHANGE ACT

I, Jack A. Fusco, certify that:

1. I have reviewed this annual report on Form 10-K of Cheniere Energy Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;

    d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 22, 2023

/s/ Jack A. Fusco
Jack A. Fusco
Chief Executive Officer of
Cheniere Energy Partners GP, LLC, the general partner of
Cheniere Energy Partners, L.P.

Exhibit 31.2

CERTIFICATION BY CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13a-14(a) AND 15d-14(a) UNDER THE EXCHANGE ACT

I, Zach Davis, certify that:

1. I have reviewed this annual report on Form 10-K of Cheniere Energy Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;

   d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 22, 2023

/s/ Zach Davis

Zach Davis
Chief Financial Officer of
Cheniere Energy Partners GP, LLC, the general partner of
Cheniere Energy Partners, L.P.

Exhibit 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

In connection with the annual report of Cheniere Energy Partners, L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2022, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jack A. Fusco, Chief Executive Officer of Cheniere Energy Partners GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to my knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 22, 2023

/s/ Jack A. Fusco
Jack A. Fusco
Chief Executive Officer of
Cheniere Energy Partners GP, LLC, the general partner of
Cheniere Energy Partners, L.P.

Exhibit 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

In connection with the annual report of Cheniere Energy Partners, L.P. (the “Partnership”) on Form 10-K for the year ended December 31, 2022, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Zach Davis, Chief Financial Officer of Cheniere Energy Partners GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to my knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 22, 2023

/s/ Zach Davis
Zach Davis
Chief Financial Officer of
Cheniere Energy Partners GP, LLC, the general partner of
Cheniere Energy Partners, L.P.