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, 2020

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. ☒

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 $8.5 billion as of June 30, 2020.

As of February 19, 2021, the registrant had 484,021,123 common units outstanding.

Documents incorporated by reference: **None**

CHENIERE ENERGY PARTNERS, L.P.

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DEFINITIONS

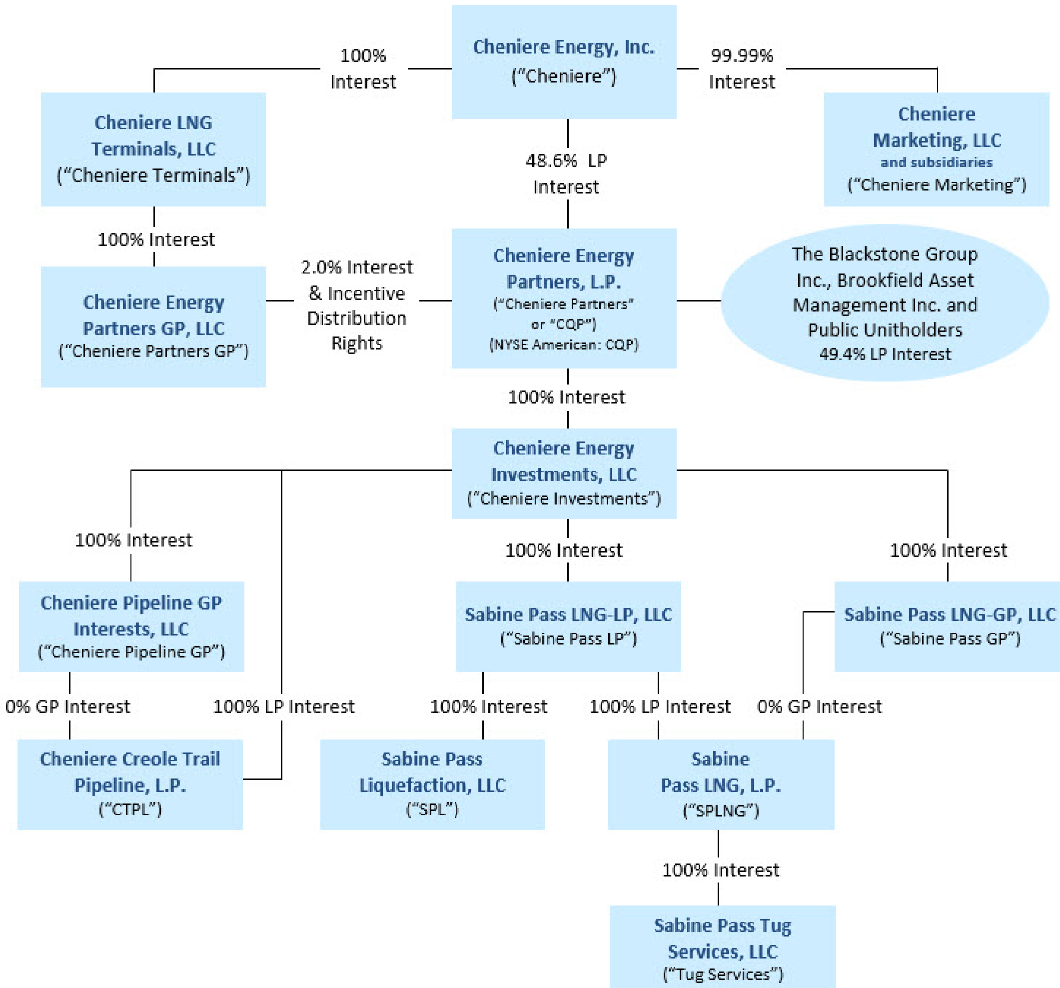
As used in this annual report, the terms listed below have the following meanings:

Common Industry and Other Terms

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
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
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, an energy unit
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, an energy unit
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, 2020, including our ownership of certain subsidiaries, and the references to these entities used in this annual report:



Unless the context requires otherwise, references to "Cheniere Partners," "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 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;
- statements regarding the outbreak of COVID-19 and its impact on our business and operating results, including any customers not taking delivery of LNG cargoes, the ongoing credit worthiness of our contractual counterparties, any disruptions in our operations or construction of our Trains and the health and safety of Cheniere's employees, and on our customers, the global economy and the demand for LNG;
- 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

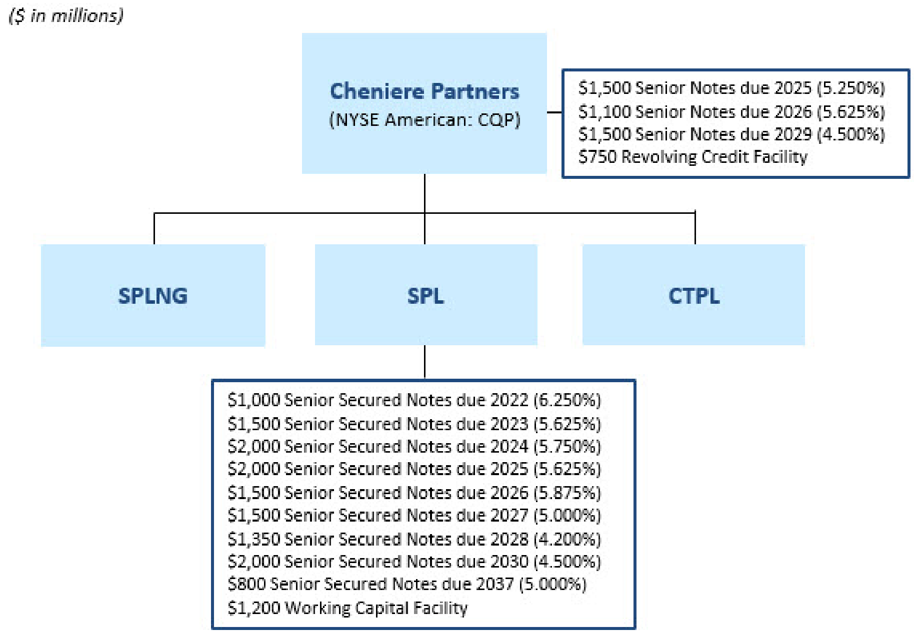
We are a publicly traded Delaware limited partnership formed by Cheniere Energy, Inc. (“Cheniere”). We provide clean, secure and affordable LNG to integrated energy companies, utilities and energy trading companies around the world. We aspire to conduct our business in a safe and responsible manner, 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.

The Sabine Pass LNG terminal is located in Cameron Parish, Louisiana, on the Sabine-Neches Waterway less than four miles from the Gulf Coast. Through our subsidiary, Sabine Pass Liquefaction, LLC (“SPL”), we are currently operating five natural gas liquefaction Trains and are constructing one additional Train that is expected to be substantially completed in the second half of 2022, for a total production capacity of approximately 30 mtpa of LNG (the “Liquefaction Project”) at the Sabine Pass LNG terminal, one of the largest LNG production facilities in the world. Through our subsidiary, Sabine Pass LNG, L.P. (“SPLNG”), we own and operate regasification facilities at the Sabine Pass LNG terminal, which includes pre-existing infrastructure of five LNG storage tanks with aggregate capacity of approximately 17 Bcfe, two existing marine berths and one under construction that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4 Bcf/d. We also own a 94-mile pipeline through our subsidiary, Cheniere Creole Trail Pipeline, L.P. (“CTPL”), that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines (the “Creole Trail Pipeline”).

We remain focused on operational excellence and customer satisfaction. Increasing demand of 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 significant land positions at the Sabine Pass LNG terminal, which provide opportunity for further liquefaction capacity expansion. The development of these sites or other projects, including infrastructure projects in support of natural gas supply and LNG demand, will require, among other things, acceptable commercial and financing arrangements before we can make a final investment decision (“FID”).

The following diagram depicts our abbreviated capital structure as of December 31, 2020:



Our Business Strategy

Our primary business strategy is to develop, construct and operate assets supported by long-term, fixed fee contracts. 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 seven of eight long-term SPA customers as of December 31, 2020;
- safely, on-time and on-budget completing construction and commencing operation of Train 6 of the Liquefaction Project;
- maximizing the production of LNG to serve our long-term customers and generating steady and stable revenues and operating cash flows; and
- strategically identifying actionable environmental solutions.

Our Business

Liquefaction Facilities

The Liquefaction Project is one of the largest LNG production facilities in the world. We are currently operating five Trains and two marine berths at the Liquefaction Project and are constructing one additional Train that is expected to be substantially completed in the second half of 2022, and a third marine berth. We have received authorization from the FERC to site, construct and operate Trains 1 through 6, as well as for the construction of the third marine berth. We have achieved substantial completion of the first five Trains of the Liquefaction Project and commenced commercial operating activities for each Train at various times starting in May 2016. The following table summarizes the project completion and construction status of Train 6 of the Liquefaction Project as of December 31, 2020:

	Train 6
Overall project completion percentage	77.6%
Completion percentage of:	
Engineering	99.0%
Procurement	99.9%
Subcontract work	54.9%
Construction	49.2%
Date of expected substantial completion	2H 2022

The following orders have been issued by the DOE authorizing the export of domestically produced LNG by vessel from the Sabine Pass LNG terminal:

- Trains 1 through 4—FTA countries and non-FTA countries through December 31, 2050, in an amount up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr of natural gas).
- Trains 1 through 4—FTA countries and non-FTA countries through December 31, 2050, in an amount up to a combined total of the equivalent of approximately 203 Bcf/yr of natural gas (approximately 4 mtpa).
- Trains 5 and 6—FTA countries and non-FTA countries through December 31, 2050, in an amount up to a combined total of 503.3 Bcf/yr of natural gas (approximately 10 mtpa).

In December 2020, the DOE announced a new policy in which it would no longer issue short-term export authorizations separately from long-term authorizations. Accordingly, the DOE amended each of SPL's long-term authorizations to include short-term export authority, and vacated the short-term orders.

An application was filed in September 2019 seeking authorization to make additional exports from the Liquefaction Project to FTA countries for a 25-year term and to non-FTA countries for a 20-year term in an amount up to the equivalent of approximately 153 Bcf/yr of natural gas, for a total Liquefaction Project export capacity of approximately 1,662 Bcf/yr. The terms of the authorizations are requested to commence on the date of first commercial export from the Liquefaction Project of the volumes contemplated in the application. In April 2020, the DOE issued an order authorizing SPL to export to FTA countries related to this application, for which the term was subsequently extended through December 31, 2050, but has not yet issued an order authorizing SPL to export to non-FTA countries for the corresponding LNG volume. A corresponding application for authorization to increase the total LNG production capacity of the Liquefaction Project from the currently authorized level to approximately 1,662 Bcf/yr was also submitted to the FERC and is currently pending.

Customers

SPL has entered into fixed price long-term SPAs generally with terms of 20 years (plus extension rights) and with a weighted average remaining contract length of approximately 17 years (plus extension rights) with eight third parties for Trains 1 through 6 of the Liquefaction Project to make available an aggregate amount of LNG that is approximately 75% of the total production capacity from these Trains, potentially increasing up to approximately 85% after giving effect to an SPA that Cheniere has committed to provide to us. Under these SPAs, the customers will purchase LNG from SPL 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 approximately 115% of Henry Hub. The 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. We refer to the fee component that is applicable regardless of a cancellation or suspension of LNG cargo deliveries under the SPAs as the fixed fee component of the price under SPL's SPAs. We refer to the fee component that is applicable only in connection with LNG cargo deliveries as the variable fee component of the price under SPL's SPAs. The variable fees under SPL's SPAs were generally sized at the time of entry into each SPA with the intent to cover the costs of gas purchases and transportation and liquefaction fuel to produce the LNG to be sold under each such SPA. 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.

In aggregate, the annual fixed fee portion to be paid by the third-party SPA customers is approximately $2.9 billion for Trains 1 through 5. After giving effect to an SPA that Cheniere has committed to provide to SPL, the annual fixed fee portion to be paid by the third-party SPA customers would increase to at least $3.3 billion, which is expected to occur upon the date of first commercial delivery of Train 6.

In addition, Cheniere Marketing has agreements with SPL to purchase: (1) at Cheniere Marketing's option, any LNG produced by SPL in excess of that required for other customers and (2) up to 30 cargoes scheduled for delivery in 2021 at a price of 115% of Henry Hub plus $0.728 per MMBtu.

The annual contracted cash flows from fixed fees of each buyer of LNG under SPL's third-party SPAs that constitute more than 10% of SPL's aggregate fixed fees under all its SPAs are:

- approximately $720 million from BG Gulf Coast LNG, LLC ("BG"), which is guaranteed by BG Energy Holdings Limited;
- approximately $550 million from Korea Gas Corporation ("KOGAS");
- approximately $550 million from GAIL;
- approximately $450 million from Naturgy LNG GOM, Limited (formerly known as Gas Natural Fenosa LNG GOM, Limited) ("Naturgy"), which is guaranteed by Naturgy Energy Group, S.A. (formerly known as Gas Natural SDG S.A.); and
- approximately $310 million from Total Gas & Power North America, Inc. ("Total"), which is guaranteed by Total S.A.

The annual aggregate fixed fees for all of SPL's other SPAs with third-parties is approximately $490 million, prior to giving effect to an SPA that Cheniere has committed to provide to SPL.

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,		
	2020	**2019**	**2018**
BG	24%	27%	28%
GAIL	18%	20%	19%
KOGAS	17%	19%	23%
Naturgy	15%	18%	21%
Total	11%	*	*

* Less than 10%

Natural Gas Transportation, Storage and Supply

To ensure SPL is able to transport adequate natural gas feedstock to the Sabine Pass LNG terminal, it has entered into transportation precedent and other agreements to secure firm pipeline transportation capacity with CTPL and third-party pipeline companies. SPL has entered into firm storage services agreements with third parties to assist in managing variability in natural gas needs for the Liquefaction Project. SPL has also entered into enabling agreements and long-term natural gas supply contracts with third parties in order to secure natural gas feedstock for the Liquefaction Project. As of December 31, 2020, SPL had secured up to approximately 4,950 TBtu of natural gas feedstock through long-term and short-term natural gas supply contracts with remaining terms that range up to 10 years, a portion of which is subject to conditions precedent.

Construction

SPL entered into lump sum turnkey contracts with Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") for the engineering, procurement and construction of Trains 1 through 6 of the Liquefaction Project, under which Bechtel charges a lump sum for all work performed and generally bears project cost, schedule and performance risks unless certain specified events occur, in which case Bechtel may cause SPL to enter into a change order, or SPL agrees with Bechtel to a change order.

The total contract price of the EPC contract for Train 6 of the Liquefaction Project is approximately $2.5 billion, including estimated costs for the third marine berth that is currently under construction. As of December 31, 2020, we have incurred $1.9 billion under this contract.

Regasification Facilities

The Sabine Pass LNG terminal has operational regasification capacity of approximately 4 Bcf/d and aggregate LNG storage capacity of approximately 17 Bcfe. Approximately 2 Bcf/d of the regasification capacity at the Sabine Pass LNG terminal has been reserved under two long-term third-party TUAs, under which SPLNG's customers are required to pay fixed monthly fees, whether or not they use the LNG terminal. Each of Total and Chevron U.S.A. Inc. ("Chevron") has reserved approximately 1 Bcf/d of regasification capacity and 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 Total's obligations under its TUA up to $2.5 billion, subject to certain exceptions, and Chevron Corporation has guaranteed Chevron's obligations under its TUA up to 80% of the fees payable by Chevron.

The remaining approximately 2 Bcf/d of capacity has been reserved under a TUA by SPL. 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 Total, whereby upon substantial completion of Train 5 of the Liquefaction Project, SPL gained access to substantially all of Total's capacity and other services provided under Total's 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, permit SPL to more flexibly manage its LNG storage capacity and accommodate the development of Train 6. Notwithstanding any arrangements between Total and SPL, payments required to be made by Total to SPLNG will continue to be made by Total to SPLNG in accordance with its TUA. During the years ended December 31, 2020, 2019 and 2018, SPL recorded $129 million, $104 million and $30 million, respectively, as operating and maintenance expense under this partial TUA assignment agreement.

Under each of these TUAs, SPLNG is entitled to retain 2% of the LNG delivered to the Sabine Pass LNG terminal.

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 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 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.

We are permitted to make sales of natural gas for resale in interstate commerce pursuant to a blanket marketing certificate automatically granted by the FERC 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 final orders in April and July 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, 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.

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, may be required prior to making any modifications to the Creole Trail Pipeline as it is a regulated, interstate natural gas pipeline. In 2013, the FERC approved CTPL's application for authorization to construct, own, operate and maintain certain new facilities in order to enable bidirectional 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, with subsequent final FERC clearance, construction was completed in 2015. In September 2013, 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 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 will be 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.

In October 2019, PHMSA published final rules revising its regulations governing the safety of certain gas transmission pipelines (effective July 1, 2020) and established new enforcement procedures for the issuance of temporary emergency orders (effective December 2, 2019).

PHMSA performs inspections of pipeline and LNG facilities and has authority to undertake enforcement actions, including issuance of civil penalties up to approximately $218,000 per day per violation, with a maximum administrative civil penalty of approximately $2 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 ("FWS"), 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 "Section 10/404 Permit"). The EPA administers the Clean Air Act, 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. Most of the regulations are already in effect, while other rules and regulations, including the new rules on speculative position limits that were finalized by the CFTC on October 15, 2020, are in the process of being phased in. The full impact of the CFTC's position limits rules is not yet known and these rules could have significant impact on our business.

As required by provisions of the Dodd-Frank Act, the CFTC and federal banking regulators have adopted rules to require 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 has 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 require significant expenditures for compliance, can affect the cost and output of operations and may impose substantial penalties for non-compliance and substantial liabilities for pollution. 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 ("CAA")

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.

In 2009, the EPA promulgated and finalized the Mandatory Greenhouse Gas Reporting Rule requiring annual reporting of greenhouse gas ("GHG") emissions from stationary sources in a variety of industries. In 2010, the EPA expanded the rule to include reporting obligations for LNG terminals. In addition, the EPA has defined GHG emissions thresholds that would subject GHG emissions from new and modified industrial sources to regulation if the source is subject to PSD Permit requirements due to its emissions of non-GHG criteria pollutants. While the EPA subsequently took a number of additional actions primarily relating to GHG emissions from the electric power generation and the oil and gas exploration and production industries, those rules were largely stayed or repealed during the Trump Administration including by amendments adopted by the EPA on February 23, 2018 and additional amendments to new source performance standards for the oil and gas industry on September 14 and 15, 2020. On January 20, 2021, President Biden issued an executive order directing the EPA to consider publishing for notice and comment a proposed rule suspending, revising, or rescinding the September 2020 rule, which could result in more stringent GHG emissions rulemaking. We are supportive of regulations reducing GHG emissions over time.

From time to time, Congress has considered proposed legislation directed at reducing GHG emissions. In addition, many states have already taken regulatory action to monitor and/or reduce emissions of GHGs, primarily through the development of GHG emission inventories or regional GHG cap and trade programs. It is not possible at this time to predict how future regulations or legislation may address GHG emissions and impact our business. However, future regulations and laws could result in increased compliance costs or additional operating restrictions and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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).

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 "ESA"), the Migratory Bird Treaty Act ("MBTA"), 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.

In August 2019, the FWS announced a series of changes to the rules implementing the ESA, including revisions to the regulations governing interagency cooperation, listing species and delisting critical habitat, and prohibitions related to threatened wildlife and plants, and in August and September 2020, the FWS proposed additional changes to its regulations for designating critical habitat. The revisions are intended to streamline these processes and create more flexibility for the FWS when making ESA-related decisions.

In addition, in January 2021, the FWS issued a final rule defining the scope of the MBTA to cover only actions intentionally directed at migratory birds, their nests or their eggs.

On January 20, 2021, President Biden issued an executive order directing the heads of all agencies to immediately review all regulatory actions taken between January 20, 2017 and January 20, 2021, including FWS regulations implementing the ESA and the MBTA and EPA regulations implementing the CWA and the Oil Pollution Act, which could result in stricter requirements with respect to endangered or threatened animal, fish and plant species and/or their designated habitats, migratory birds, wetlands or other natural resources.

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

If and 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. Cheniere is currently operating two Trains and is commissioning one additional Train at a natural gas liquefaction facility near Corpus Christi, Texas and Corpus Christi Liquefaction, LLC (“CCL”) has entered into fixed price SPAs generally with terms of 20 years (plus extension rights) and with a weighted average remaining contract length of approximately 19 years (plus extension rights) with nine third parties for the sale of LNG from this natural gas liquefaction facility, and may continue to enter into commercial agreements with respect to this natural gas liquefaction facility that might otherwise have been entered into with respect to Train 6. Revenues associated with any incremental volumes of the Liquefaction Project, including those under the Cheniere Marketing SPA discussed above, 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 markets than us. Our affiliates have proximity to our customers, with offices located in Houston, London, Singapore, Beijing and Tokyo.

SPLNG currently does not experience competition for its terminal capacity because the entire approximately 4 Bcf/d of regasification capacity that is available at the Sabine Pass LNG terminal has been fully contracted. If and when SPLNG has to replace any TUAs, it will compete with other then-existing LNG terminals for customers.

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 rate of fuel switching for power generation from coal, nuclear or oil to natural gas and economic growth in developing countries. In addition, Cheniere’s ability to obtain additional funding to execute its business strategy is subject to the investment community’s appetite for investment in LNG and natural gas infrastructure and Cheniere’s 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. Players 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, hundreds of billions of dollars are being invested across Europe and Asia in natural gas projects under construction, and if we included planned commitments, the total would exceed $1 trillion. Some examples include India’s commitment to invest over $60 billion to drive its gas-based economy, Europe's commitment of well over $100 billion in gas-fired power, import terminals and pipelines, and China's hundreds of billions all along the natural gas value chain. We highlight regasification capacity, which will not only expand existing import capacities in rapidly growing markets like China and India, but also add new import markets all over the globe, raising the total to approximately 60 by 2030 from 43 today and just 15 markets as recently as 2005.

As a result of these dynamics, global demand for natural gas is projected by the International Energy Agency to grow by approximately 21 trillion cubic feet ("Tcf") between 2019 and 2030 and 42 Tcf between 2019 and 2040. LNG's share is seen growing from about 12% in 2019 to about 16% of the global gas market in 2030 and 19% in 2040. Wood Mackenzie Limited ("WoodMac") forecasts that global demand for LNG will increase by approximately 56%, from approximately 347 mtpa, or 16.6 Tcf, in 2019, to approximately 541 mtpa, or 26.0 Tcf, in 2030 and to 723 mtpa or 34.7 Tcf in 2040. WoodMac also forecasts LNG production from existing operational facilities and new facilities already under construction will be able to supply the market with approximately 476 mtpa in 2030, declining to 381 mtpa in 2040. This will result in a market need for construction of an additional approximately 65 mtpa of LNG production by 2030 and about 343 mtpa by 2040. As a cleaner burning fuel with far 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 the decline in oil prices 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. We have contracted approximately 75% of the total production capacity from the Liquefaction Project on a term basis, with approximately 17 years of average remaining life as of December 31, 2020, 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. As of January 31, 2021, U.S. natural gas prices indicate that LNG exported from the U.S. continues to be competitively priced, supporting the opportunity for U.S. LNG to fill uncontracted future demand through the execution of long-term and medium-term contracting of LNG from our terminal.

Subsidiaries

Our assets are generally 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 January 31, 2021, Cheniere and its subsidiaries had 1,519 full-time employees, including 490 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.

Risk Factor Summary

Each of the risk factors outlined below are discussed more fully following this summary:

Risks Relating to Our Financial Matters

Our operating results, cash flows and/or liquidity could be adversely affected by the following factors:

- Our existing level of cash resources and significant debt
- Dilution of our unitholders' proportionate indirect interests in our assets, business operations and our projects from sale of equity or equity-related securities or assets
- Failure by any significant customer to perform under their long-term contracts with us
- Termination of our customer contracts under certain circumstances
- Use of hedging arrangements
- Certain rules and regulations could adversely affect our ability to hedge risks

Risks Relating to Our Business

The operations of our Sabine Pass LNG terminal, construction of the remaining or additional Trains and the commercialization of the LNG produced could be adversely affected by the following factors:

- COVID-19 global pandemic and volatility in the energy markets
- Outbreaks of infectious diseases, such as the outbreak of COVID-19, at one or more of our facilities
- Cost overruns and delays in construction, as well as difficulties in obtaining sufficient financing to pay for such costs and delays
- Hurricanes or other disasters
- Failure to obtain and maintain approvals and permits from governmental and regulatory agencies
- Delays in construction leading to reduced revenues or termination of one or more of the SPAs by our customers
- Dependency on Cheniere for key personnel, and the unavailability of skilled workers or failure to attract and retain qualified personnel, including changes in our general partner's senior management or other key personnel
- Conflict of interest with Cheniere and its affiliates
- Dependency on Bechtel and other contractors
- Unavailability of third-party pipelines, and other facilities interconnected to our pipelines and facilities, to transport natural gas
- Inability to purchase or receive physical delivery of sufficient natural gas to satisfy our delivery obligations under the SPAs
- Significant construction and operating hazards and uninsured risks
- Cyclical or other changes in the demand for and price of LNG and natural gas
- Failure of imported or exported LNG to be a competitive source of energy for the United States or international markets
- Various economic and political factors
- Impediments to the transport of LNG, such as shortages of LNG vessels, or operational impacts on LNG shipping
- Securing firm pipeline transportation capacity on economic terms that is sufficient to meet our feed gas transportation requirements

- Competition based upon the international market price for LNG
- Terrorist attacks, cyber incidents or military campaigns
- Existing and future environmental and similar laws and governmental regulations
- FERC regulations
- A major health and safety incident relating to our business
- Pipeline safety integrity programs and repairs
- Loss of our right to situate our pipelines on property owned by third parties
- Inaccurate estimates for the future capacity ratings and performance capabilities of the Liquefaction Project
- Lack of diversification
- Limited growth that could result from failure to make acquisitions or implementation of capital expansion projects not made on economically acceptable terms
- Acquisitions that may limit our ability to make distributions
- Impairments to goodwill or long-lived assets

Risks Relating to Our Cash Distributions

The amount of cash available for cash distributions and our ability to pay cash distribution could be adversely affected by the following factors:

- Ability to maintain or increase our cash available for distribution
- Satisfaction of our indebtedness and terms of our future indebtedness
- Restriction of our subsidiaries to make distributions to us
- Restrictions in agreements governing our subsidiaries' indebtedness
- Payment of management fees and cost reimbursements to our general partner and its affiliates
- Level of our cash flow
- Ability to make accretive acquisitions or implement accretive capital expansion projects

Risks Relating to an Investment in Us and Our Common Units

Investment in us and our common units could be adversely affected by the following factors:

- Conflicts of interest and limited fiduciary duties by our general partner and its affiliates
- Competition by Cheniere
- Limitation of our general partner's fiduciary duties to our unitholder
- Unitholders' limited voting rights
- Inability to initially remove our general partner without its consent
- Transfer of control of our general partner to a third party without unitholder consent
- Restriction of voting rights of unitholders owning 20% or more of our units
- Certain provisions of our partnership agreement which could discourage a change of control
- Limitations on the liability of holders of limited partner interests in certain circumstances
- Liability to repay distributions wrongfully made
- Dilution from issuance of additional units without unitholder approval
- Fluctuation in the market price of our common units
- Sale of limited partner units by affiliates of our general partner or affiliates of Blackstone or Brookfield

Risks Relating to Tax Matters

The following tax matters could adversely affect our business or our cash available for distribution and/or our unitholders:

- Tax treatment as a corporation instead of a partnership for federal income tax purposes
- Material amount of additional entity-level taxation by individual states
- Change in tax treatment from legislative, judicial or administrative changes and differing interpretations
- Proration of items between transferors and transferees of our common units
- Successful IRS contest of the federal income tax positions that we take
- Audit adjustments to our income tax returns by the IRS
- Taxation on unitholders' share of our taxable income
- Tax gain or loss on the disposition of our common units
- Limitation on unitholders' ability to deduct interest expense
- Unique tax issues for unitholders that are tax-exempt entities
- Subjectivity to U.S. taxes and withholding by non-U.S. unitholders
- IRS challenge of our treatment of our unitholders' tax benefits

- Subjectivity to state and local taxes and return filing requirements by our unitholders
- IRS challenge of our valuation methodologies in determining a unitholder's allocation of income, gain, loss and deduction
- Tax consequences for unitholders whose common units are the subject of a securities loan

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, 2020, we had $1.2 billion of cash and cash equivalents, $0.1 billion of current restricted cash, $750 million of available commitments under the $750 million revolving credit facility (the "2019 CQP Credit Facilities") and $17.8 billion of total debt outstanding on a consolidated basis (before unamortized premium, discount and debt issuance costs), excluding $413 million aggregate outstanding letters of credit. We incur, and will incur, significant interest expense relating to the assets at the Sabine Pass LNG terminal. Our ability to fund our capital expenditures and refinance our indebtedness will depend on our ability to access additional project financing as well as the debt and equity capital markets. A variety of factors beyond our control could impact the availability or cost of capital, including domestic or international economic conditions, increases in key benchmark interest rates and/or credit spreads, the adoption of new or amended banking or capital market laws or regulations 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.

We may sell equity or equity-related securities or assets, including additional common units. Such sales could dilute our unitholders' proportionate indirect interests in our assets, business operations, Liquefaction Project and other projects.

We have historically pursued a number of alternatives in order to finance the construction of our Trains, including potential issuances and sales of additional equity or equity-related securities. Such sales, in one or more transactions, could dilute our unitholders' proportionate indirect interests in our assets, business operations and proposed projects, including the Liquefaction Project. In addition, such sales, or the anticipation of such sales, could adversely affect the market price of our common units.

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, 2020, SPL had SPAs with eight third-party customers and SPLNG had TUAs with two third-party customers. We are dependent on each customer's continued willingness and ability to perform its obligations under its SPA or TUA. We are exposed to the credit risk of any guarantor of these customers' obligations under their respective agreements in the event that we must seek recourse under a guaranty. As a result of the disruptions caused by the COVID-19 pandemic and the volatility in the energy markets, we believe we are exposed to heightened credit and performance risk of our customers. Additionally, some customers have indicated to us that COVID-19 has impacted their operations and/or may impact their operations in the future. Some of our SPA customers' primary countries of business have experienced a significant number of COVID-19 cases and/or have been subject to government imposed lockdown or quarantine measures. Although we believe that impacts of the COVID-19 pandemic on LNG regasification facilities, downstream markets and broader energy demand do not constitute valid force majeure claims under our FOB LNG SPAs, if any significant customer fails to perform its obligations under its SPA or TUA, our business, contracts, financial condition, operating results, cash flow, liquidity and prospects could be materially and adversely affected, even if we were ultimately successful in seeking damages from that customer or its guarantor, if any, for a breach of the agreement.

Each of our customer contracts is subject to termination under certain circumstances.

Each of SPL's SPAs contains various termination rights allowing our customers to terminate their SPAs, including, without limitation: (1) upon the occurrence of certain events of force majeure; (2) if we fail to make available specified scheduled cargo quantities; and (3) delays in the commencement of commercial operations. We may not be able to replace these SPAs on desirable terms, or at all, if they are terminated.

Each of SPLNG's long-term TUAs contains various termination rights. For example, each customer may terminate its TUA if the Sabine Pass LNG terminal experiences a force majeure delay for longer than 18 months, fails to redeliver a specified amount of natural gas in accordance with the customer's redelivery nominations or fails to accept and unload a specified number of the customer's proposed LNG cargoes. SPLNG may not be able to replace these TUAs on desirable terms, or at all, if they are terminated.

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

To reduce our exposure to fluctuations in commodity-related marketing and price risks, we enter into derivative financial instruments, including futures, swaps and option contracts. To the extent we hedge our exposure to commodity price, we forego the benefits we would otherwise experience if commodity prices were to change favorably to our hedged position. Hedging arrangements could also expose us to risk of financial loss in some circumstances, including when:

- expected supply is less than the amount hedged or is otherwise imperfect;
- the counterparty to the hedging contract defaults on its contractual obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

Our use of derivative financial instruments are recorded at fair value on our Consolidated Balance Sheets with changes in the fair value resulting from fluctuations in the underlying commodity prices or hedged item recognized in earnings, unless they satisfy criteria for, and we elect, the normal purchases and sales exception or hedge accounting treatment. All of our derivative financial instruments do not qualify for these exceptions from fair value reporting through earnings. As a result, our quarterly and annual results are subject to significant fluctuations caused by changes in fair value, including circumstances in which there is no underlying economic impact yet realized.

The use of derivatives also may require the posting of cash collateral with counterparties, which can impact working capital when commodity prices change.

The regulatory and other provisions of the Dodd-Frank Act and the rules adopted thereunder and other regulations could adversely affect our ability to hedge risks associated with our business and our operating results and cash flows.

The provisions of the Dodd-Frank Act and the rules adopted by the CFTC, the SEC and other federal regulators establishing federal regulation of the over-the-counter ("OTC") derivatives market and entities like us that participate in that market may adversely affect our ability to manage certain of our risks on a cost effective basis. Such laws and regulations may also adversely affect our ability to execute our strategies with respect to hedging our exposure to variability in expected future cash flows attributable to the future sale of our LNG inventory and to price risk attributable to future purchases of natural gas to be utilized as fuel to operate our LNG terminal and to secure natural gas feedstock for our Liquefaction Project.

As required by the Dodd-Frank Act, the CFTC and federal banking regulators have adopted rules to require certain market participants to collect and post initial and/or variation margin with respect to uncleared swaps from their counterparties that are financial end users and certain registered swap dealers and major swap participants. Although we believe we will not be required to post margin with respect to any uncleared swaps we enter into in the future, were we required to post margin as to our uncleared swaps in the future, our cost of entering into and maintaining swaps would be increased. Our counterparties that are subject to the regulations imposing the Basel III capital requirements on them may increase the cost to us of entering into swaps with them or, although not required to collect margin from us under the margin rules, contractually require us to post collateral with them in connection with such swaps in order to offset their increased capital costs or to reduce their capital costs to maintain those swaps on their balance sheets.

Risks Relating to Our Business

The COVID-19 global pandemic and volatility in the energy markets may materially and adversely affect our business, financial condition, operating results, cash flow, liquidity and prospects.

The COVID-19 global pandemic has resulted in significant disruption globally. Actions taken by various governmental authorities, individuals and companies around the world to prevent the spread of COVID-19 have restricted travel, business operations, and the overall level of individual movement and in-person interaction across the globe. Additionally, recent disputes over production levels between members of the Organization of Petroleum Exporting Countries and other oil producing countries have resulted in increased volatility in oil and natural gas prices.

The extent, duration and magnitude of the COVID-19 pandemic's effects will depend on future developments, all of which are highly uncertain and difficult to predict, including the impact of the pandemic on global and regional economies, travel, and economic activity, as well as actions taken by governments, businesses and individuals in response to the pandemic or any future resurgence. These developments include the impact of the COVID-19 pandemic on unemployment rates, the demand for oil and natural gas, levels of consumer confidence and the post-pandemic pace of recovery.

Many uncertainties remain with respect to the COVID-19 pandemic, and we continue to monitor the rapidly evolving situation. The COVID-19 pandemic alone or coupled with continued volatility in the energy markets may materially and adversely affect our business, financial condition, operating results, cash flow, liquidity and prospects or have the effect of heightening many of the other risks described herein. The extent to which our business, contracts, financial condition, operating results, cash flow, liquidity and prospects are affected by the COVID-19 global pandemic or volatility in the energy markets will depend on various factors beyond our control and are highly uncertain, including the duration and scope of the outbreak, decreased demand for LNG and the resulting economic effects of the COVID-19 global pandemic.

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

Federal, state and local governments have enacted various measures to try to contain the outbreak of COVID-19, such as travel bans and restrictions, quarantines, shelter-in-place orders and business shutdowns. Our facilities at the Sabine Pass LNG terminal are critical infrastructure and have continued to operate during the outbreak, which means that Cheniere must keep its employees who operate our facilities safe and minimize unnecessary risk of exposure to the virus. In response, Cheniere has taken extra precautionary measures to protect the continued safety and welfare of its employees who continue to work at our facilities and have modified certain business and workforce practices, such as implementing work from home policies where appropriate, but there can be no assurances that these measures will prevent any outbreak. Furthermore, the measures taken to prevent an outbreak at our facilities have resulted in increased costs and it is unclear how long such increased costs will continue to be incurred. If a large number of Cheniere's employees in those critical facilities were to contract COVID-19 at the same time, our operations could be adversely affected.

Cost overruns and delays in the completion of Train 6 or any future Trains, as well as difficulties in obtaining sufficient financing to pay for such costs and delays, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

The actual construction costs of Train 6 and any future Trains may be significantly higher than our current estimates as a result of many factors, including change orders under existing or future EPC contracts resulting from the occurrence of certain specified events that may give our EPC contractor the right to cause us to enter into change orders or resulting from changes with which we otherwise agree. We have already experienced increased costs due to change orders. As construction progresses, we may decide or be forced to submit change orders to our contractor that could result in longer construction periods, higher construction costs or both, including change orders to comply with existing or future environmental or other regulations.

The COVID-19 pandemic and the resulting actions taken by governmental and regulatory authorities to prevent the spread of COVID-19 may cause a slow-down in the construction of one or more Trains. Our EPC contractor has advised us of voluntary proactive measures it is taking to protect employees and to mitigate risks associated with COVID-19, however, it has not indicated that there will be any changes to the project cost or schedule and is still performing its obligations under its EPC contract. While the construction of Train 6 is continuing, if there were a major outbreak of COVID-19 at any construction site or the implementation of restrictions by the government that prevented construction for an extended period, we could experience significant delays in the construction of one or more Trains.

Delays in the construction of one or more Trains beyond the estimated development periods, as well as change orders to our existing EPC contract or any future EPC contract related to additional Trains, could increase the cost of completion beyond the amounts that we estimate, which could require us to obtain additional sources of financing to fund our operations until the Liquefaction Project is fully constructed (which could cause further delays). Our ability to obtain financing that may be needed to provide additional funding to cover increased costs will depend, in part, on factors beyond our control. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, or at all. Even if we are able to obtain financing, we may have to accept terms that are disadvantageous to us or that may have a material adverse effect on our current or future business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Hurricanes or other disasters could result in an interruption of our operations, a delay in the completion of the Liquefaction Project, damage to our Liquefaction Project and increased insurance costs, all of which could adversely affect us.

Hurricanes Katrina and Rita in 2005, Hurricane Ike in 2008, Hurricane Harvey in 2017 and Hurricanes Laura and Delta in 2020 caused temporary suspension in construction or operation of our Liquefaction Project or caused minor damage to our Liquefaction Project. 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, 2020, 17 TBtu was loaded at affiliate facilities pursuant to this agreement. Future storms and related storm activity and collateral effects, or other disasters such as explosions, fires, floods or accidents, could result in damage to, or interruption of operations at, the Sabine Pass LNG terminal or related infrastructure, as well as delays or cost increases in the construction and the development of the Liquefaction Project and related infrastructure and increase our insurance premiums. The U.S. Global Change Research Program has reported that the U.S.'s energy and transportation systems are expected to be increasingly disrupted by climate change and extreme weather events. An increase in frequency and severity of extreme weather events such as storms, floods, fires and rising sea levels could have an adverse effect on our operations.

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 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, LNG terminals, including the Liquefaction Project, and other facilities, and 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. Although the FERC has issued orders under Section 3 of the NGA authorizing the siting, construction and operation of the six Trains and related facilities and Section 7 of the NGA authorizing the construction and operation of the Creole Trail Pipeline, the FERC orders require us to comply with certain ongoing conditions and obtain certain additional approvals in conjunction with ongoing construction and operations of the Liquefaction Project and the operations of the Creole Trail Pipeline. We will be required to obtain similar approvals and permits with respect to any expansion or modification of our liquefaction and pipeline facilities. We cannot control the outcome of the regulatory review and approval processes. Certain of these governmental permits, approvals and authorizations are or may be subject to rehearing requests, appeals and other challenges.

Authorizations obtained from the FERC, DOE and other federal and state regulatory agencies also contain ongoing conditions, and additional approval and permit requirements may be imposed. We do not know whether or when any such approvals or permits can be obtained, or whether any existing or potential interventions or other actions by third parties will interfere with our ability to obtain and maintain such permits or approvals. If we are unable to obtain and maintain the necessary approvals and permits, including as a result of untimely notices or filings, we may not be able to recover our investment in our projects. Additionally, government disruptions, such as a U.S. government shutdown, may delay or halt our ability to obtain and maintain necessary approvals and permits. 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, and failure to obtain and maintain any of these permits, approvals or authorizations could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Delays in the completion of one or more Trains could lead to reduced revenues or termination of one or more of the SPAs by our customers.

Any delay in completion of a Train could cause a delay in the receipt of revenues projected therefrom or cause a loss of one or more customers in the event of significant delays. In particular, each of our SPAs provides that the customer may terminate that SPA if the relevant Train does not timely commence commercial operations. As a result, any significant construction delay, whatever the cause, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We are entirely dependent on Cheniere, including employees of Cheniere and its subsidiaries, for key personnel, and the unavailability of skilled workers or 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 January 31, 2021, Cheniere and its subsidiaries had 1,519 full-time employees, including 490 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 liquefaction 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 or other general inflationary pressures, changes in applicable laws and regulations or labor dispute 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.

We have numerous contractual and commercial relationships, and conflicts of interest, with Cheniere and its affiliates, including Cheniere Marketing.

We have agreements to compensate and to reimburse expenses of affiliates of Cheniere. In addition, Cheniere Marketing has entered into an SPA to purchase: (1) at Cheniere Marketing's option, any LNG produced by SPL in excess of that required for other customers and (2) up to 30 cargoes scheduled for delivery in 2021 at a price of 115% of Henry Hub plus $0.728 per MMBtu. 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 two Trains and is constructing one additional Train 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 into commercial arrangements with respect to this liquefaction facility that might otherwise have been entered into with respect to Train 6 or any future Trains.

We expect that there will be additional agreements or arrangements with Cheniere and its affiliates, including future transportation, interconnection and gas balancing agreements with one or more Cheniere-affiliated natural gas pipelines 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 will be involved.

We are dependent on Cheniere and its affiliates to provide services to us. If Cheniere or its affiliates are unable or unwilling to perform according to the negotiated terms and timetable of their respective agreement for any reason or terminate their agreement, we would be required to engage a substitute service provider. This could result in a significant interference with operations and increased costs.

We are dependent on Bechtel and other contractors for the successful completion of the Liquefaction Project.

Timely and cost-effective completion of the Liquefaction Project in compliance with agreed specifications is central to our business strategy and is highly dependent on the performance of Bechtel and our other contractors under their agreements. The ability of Bechtel and our other contractors to perform successfully under their agreements is dependent on a number of factors, including their ability to:

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

Although some agreements may provide for liquidated damages if the contractor fails to perform in the manner required with respect to certain of its obligations, the events that trigger a requirement to pay liquidated damages may delay or impair the operation of the Liquefaction Project, and any liquidated damages that we receive may not be sufficient to cover the damages that we suffer as a result of any such delay or impairment. The obligations of Bechtel and our other contractors to pay liquidated damages under their agreements are subject to caps on liability, as set forth therein.

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

If third-party pipelines and other facilities interconnected to our pipeline and facilities are or become unavailable to transport natural gas, this 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 the Liquefaction Project and to and from the Creole Trail Pipeline. If the construction of new or modified pipeline connections is not completed on schedule or any pipeline connection were to become unavailable for current or future volumes of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our ability to meet our SPA obligations and continue shipping natural gas from producing regions or to end markets could be restricted, thereby reducing our revenues 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. However, we may not be able to purchase or receive physical delivery of sufficient quantities of natural gas to satisfy those obligations, which may provide affected SPA customers with the right to terminate their SPAs. Our failure to purchase or receive physical delivery of sufficient quantities of natural gas 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, 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. 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 flows, 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:

- additions to competitive regasification capacity in North America, Europe, Asia and other markets, which could divert LNG from the Sabine Pass LNG terminal;
- competitive liquefaction capacity in North America;
- insufficient or oversupply of natural gas liquefaction or receiving capacity worldwide;
- insufficient LNG tanker capacity;
- weather conditions, including extreme weather events and temperature volatility resulting from climate change;
- 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 offer LNG regasification services or provide natural gas liquefaction capabilities at reduced prices;
- changes in supplies of, and prices for, alternative energy sources such as coal, oil, nuclear, hydroelectric, wind and solar energy, which may reduce the demand for natural gas;
- changes in regulatory, tax or other governmental policies regarding imported or exported LNG, natural gas or alternative energy sources, which may reduce the demand for imported or exported LNG and/or natural gas;
- political conditions in natural gas producing regions;
- 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 into or exports from North America; and
- cyclical trends in general business and economic conditions that cause changes in the demand for natural gas.

Adverse trends or developments affecting any of these factors could result in decreases in the price of LNG and/or natural gas, which could materially and adversely affect the performance of our customers, and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flows, liquidity and prospects.

Failure of imported or exported LNG to be a competitive source of energy for the United States or 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.

Although SPL has entered into arrangements to utilize up to approximately three-quarters of the regasification capacity at the Sabine Pass LNG terminal in connection with operations of the Liquefaction Project, operations at the Sabine Pass LNG terminal are dependent, in part, upon the ability of our TUA customers to import LNG supplies into the United States, which is primarily dependent upon LNG being a competitive source of energy in North America. In North America, due mainly to a historically abundant supply of natural gas and discoveries of substantial quantities of unconventional, or shale, natural gas, imported LNG has not developed into a significant energy source. The success of the regasification services component of our business plan is dependent, in part, on the extent to which LNG can, for significant periods and in significant volumes, be produced internationally and delivered to North America at a lower cost than the cost to produce some domestic supplies of natural gas, or other alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas have recently been and may continue to be discovered in North America, which could further increase the available supply of natural gas and could result in natural gas being available at a lower cost than imported LNG.

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 or export LNG from or to 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 or regasification facilities in the United States.

In addition to natural gas, LNG also competes with other sources of energy, including coal, oil, nuclear, hydroelectric, wind and solar energy. 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 a result of these and other factors, LNG may not be a competitive source of energy in the United States or internationally. The failure of LNG to be a competitive supply alternative to local natural gas, oil and other alternative energy sources in markets accessible to our customers could adversely affect the ability of our customers to deliver LNG from the United States or to the United States on a commercial basis. Any significant impediment to the ability to deliver LNG to or from the United States generally, or to the Sabine Pass LNG terminal or from the Liquefaction Project specifically, could have a material adverse effect on our customers and on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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

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

- increased construction costs;
- economic downturns, increases in interest rates or other events that may affect the availability of sufficient financing for LNG projects on commercially reasonable terms;
- decreases in the price of LNG, which might decrease the expected returns relating to investments in LNG projects;
- the inability of project owners or operators to obtain governmental approvals to construct or operate LNG facilities;
- political unrest or local community resistance to the siting of LNG facilities due to safety, environmental or security concerns; and
- any significant explosion, spill or similar incident involving an LNG facility or LNG vessel.

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

The construction and delivery of LNG vessels require significant capital and long construction lead times. Additionally, the availability of LNG vessels and transportation costs could be impacted to the detriment of our business and our customers because of:

- an inadequate number of shipyards constructing LNG vessels and a backlog of orders at these shipyards;
- shortages of or delays in the receipt of necessary construction materials;
- political or economic disturbances;
- changes in governmental regulations or maritime self-regulatory organizations;
- work stoppages or other labor disturbances;
- bankruptcy or other financial crisis of shipbuilders or shipowners;
- quality or engineering problems;
- disruptions to maritime transportation routes; and
- weather interference or a catastrophic event, such as a major earthquake, tsunami or fire.

We may not be able to secure firm pipeline transportation capacity on economic terms that is sufficient to meet our feed gas transportation requirements, which could have a material adverse effect on us.

We have contracted for firm capacity for our natural gas feedstock transportation requirements for the Liquefaction Project. If and when we need to replace one or more of our existing agreements with these interconnecting pipelines, we may not be able to do so on commercially reasonable terms or at all, which could impair our ability to fulfill our obligations under certain of our SPAs and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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

The 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 with respect to Train 6 or any future Trains. 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 the 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 the 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.

Terrorist attacks, cyber incidents or military campaigns may adversely impact our business.

A terrorist attack, cyber incident or military incident involving an LNG facility, our infrastructure or an LNG vessel may result in delays in, or cancellation of, construction of new LNG facilities, including Train 6, which would increase our costs and decrease our cash flows. A terrorist incident or cyber incident may also result in temporary or permanent closure of existing LNG facilities, including the Sabine Pass LNG terminal or the Creole Trail Pipeline, which could increase our costs and decrease our cash flows, depending on the duration and timing of the closure. Our operations could also become subject to increased governmental scrutiny that may result in additional security measures at a significant incremental cost to us. In addition, the threat of terrorism and the impact of military campaigns may lead to continued volatility in prices for natural gas that could adversely affect our business and our customers, including their ability to satisfy their obligations to us under our commercial agreements. Instability in the financial markets as a result of terrorism, cyber incidents or war could also materially adversely affect our ability to raise capital. The continuation of these developments may subject our construction and our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Existing and future 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 and pipeline, including FERC and PHMSA, to issue compliance orders, 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 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.

In 2009, the EPA promulgated and finalized the Mandatory Greenhouse Gas Reporting Rule requiring annual reporting of GHG emissions from stationary sources in a variety of industries. In 2010, the EPA expanded the rule to include reporting obligations for LNG terminals. In addition, the EPA has defined GHG emissions thresholds that would subject GHG emissions from new and modified industrial sources to regulation if the source is subject to PSD Permit requirements due to its emissions of non-GHG criteria pollutants. While the EPA subsequently took a number of additional actions primarily relating to GHG emissions from the electric power generation and the oil and gas exploration and production industries, those rules were largely stayed or repealed during the Trump Administration including by amendments adopted by the EPA on February 23, 2018 and additional amendments to new source performance standards for the oil and gas industry on September 14 and 15, 2020. On January 20, 2021, President Biden issued an executive order directing the EPA to consider publishing for notice and comment a proposed rule suspending, revising, or rescinding the September 2020 rule, which could result in more stringent GHG emissions rulemaking. In addition, other federal and state initiatives may be considered in the future to address GHG emissions through, for example, United States treaty commitments, direct regulation, market-based regulations such as a carbon emissions tax or cap-and-trade programs or clean energy 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. We are supportive of regulations reducing GHG emissions over time.

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. 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.

The Creole Trail Pipeline and its FERC gas tariff are subject to FERC regulation.

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 CTPL must be just and reasonable, and CTPL is prohibited from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service. If we fail to comply with all applicable statutes, rules, regulations and orders, CTPL could be subject to substantial penalties and fines.

In addition, as a natural gas market participant, should CTPL fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, CTPL 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 $1.3 million per day for each violation.

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

Health and safety performance is critical to the success of all areas of our business. Any failure in health and safety performance may result in personal harm or injury, penalties for non-compliance with relevant regulatory requirements or litigation, and a failure that results in a significant health and safety incident is likely to be costly in terms of potential liabilities. Such a failure could generate public concern and have a corresponding impact on our reputation and our relationships with relevant regulatory agencies and local communities, which in turn could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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

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

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;

- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventative and mitigating actions.

CTPL is required to maintain pipeline integrity testing programs that are intended to assess pipeline integrity. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures. Should CTPL fail to comply with applicable statutes and the Office of Pipeline Safety's rules and related regulations and orders, CTPL could be subject to significant penalties and fines.

Our business could be materially and adversely affected if we lose the right to situate the Creole Trail Pipeline on property owned by third parties.

We do not own the land on which the Creole Trail Pipeline is situated, and we are subject to the possibility of increased costs to retain necessary land use rights. If we were to lose these rights or be required to relocate the Creole Trail Pipeline, our business could be materially and adversely affected.

We are relying on estimates for the future capacity ratings and performance capabilities of the Liquefaction Project, and these estimates may prove to be inaccurate.

We are relying on third parties, principally Bechtel, for the design and engineering services underlying our estimates of the future capacity ratings and performance capabilities of the Liquefaction Project. If any Train, when actually constructed, fails to have the capacity ratings and performance capabilities that we intend, our estimates may not be accurate. Failure of any of our Trains to achieve our intended capacity ratings and performance capabilities could prevent us from achieving the commercial start dates under our SPAs and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Our lack of diversification could have an adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Substantially all of our anticipated revenue in 2021 will be dependent upon one facility, the Sabine Pass LNG terminal located in southern Louisiana. Due to our lack of asset and geographic diversification, an adverse development at the Sabine Pass LNG terminal, including the related pipeline, or in the LNG industry, would have a significantly greater impact on our financial condition and operating results than if we maintained more diverse assets and operating areas.

If we do not make acquisitions or implement capital expansion projects on economically acceptable terms, our future growth and our ability to increase distributions to our unitholders will be limited.

Our ability to grow depends on our ability to make accretive acquisitions or implement accretive capital expansion projects, such as the Liquefaction Project. We may be unable to make accretive acquisitions or implement accretive capital expansion projects for any of the following reasons:

- if we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- if we are unable to identify attractive capital expansion projects or negotiate acceptable engineering procurement and construction arrangements for them;
- if we are unable to obtain necessary governmental approvals;
- if we are unable to obtain financing for the acquisitions or capital expansion projects on economically acceptable terms, or at all;
- if we are unable to secure adequate customer commitments to use the acquired or expansion facilities; or
- if we are outbid by competitors.

If we are unable to make accretive acquisitions or implement accretive capital expansion projects, then our future growth and ability to increase distributions to our unitholders will be limited.

We intend to pursue acquisitions of additional LNG terminals, natural gas pipelines and related assets in the future, either directly from Cheniere or from third parties. However, Cheniere is not obligated to offer us any of these assets other than, in certain circumstances under an investors rights agreement with Blackstone CQP Holdco, its liquefaction project at Corpus Christi, Texas. If Cheniere does offer us the opportunity to purchase assets, we may not be able to successfully negotiate a purchase and sale agreement and related agreements, we may not be able to obtain any required financing for such purchase and we may not be able to obtain any required governmental and third-party consents. The decision whether or not to accept such offer, and to negotiate the terms of such offer, will be made by the conflicts committee of our general partner, which may decline the opportunity to accept such offer for a variety of reasons, including a determination that the acquisition of the assets at the proposed purchase price would not result in an increase, or a sufficient increase, in our adjusted operating surplus per unit within an appropriate timeframe.

If we make acquisitions, such acquisitions could adversely affect our business and ability to make distributions to our unitholders.

If we make any acquisitions, they will involve potential risks, including:

- an inability to integrate successfully the businesses that we acquire with our existing business;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the cash generated, or to be generated, by the business acquired or the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns; and
- unforeseen difficulties encountered in operating new business segments or in new geographic areas.

If we consummate any future acquisitions, our capitalization and operating results may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of our future funds and other resources. In addition, if we issue additional units in connection with future growth, our existing unitholders' interest in us will be diluted, and distributions to our unitholders may be reduced.

We may incur impairments to long-lived assets.

We test our long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. Significant negative industry or economic trends, reduced estimates of future cash flows for our business or disruptions to our business could lead to an impairment charge of our long-lived assets. Our valuation methodology for assessing impairment requires management to make judgments and assumptions based on historical experience and to rely heavily on projections of future operating performance. Projections of future operating results and cash flows may vary significantly from results. In addition, if our analysis results in an impairment to our long-lived assets, we may be required to record a charge to earnings in our Consolidated Financial Statements during a period in which such impairment is determined to exist, which may negatively impact our operating results.

Risks Relating to Our Cash Distributions

We may not be successful in our efforts to maintain or increase our cash available for distribution to cover the distributions on our common units.

Prior to the quarter ended September 30, 2017, we historically paid the initial quarterly distribution of $0.425 on each of our common units and the related distribution on our general partner units, and did not pay any distributions on our subordinated units. For the quarter ended September 30, 2017 and in each of the subsequent quarters, we have paid increasing distributions on each of our common and subordinated units and the related distribution on our general partner units. For the quarter ended December 31, 2017 and in each of the subsequent quarters, we also paid the related distribution to the holder of our incentive distribution rights ("IDRs"). During the year ended December 31, 2020, we paid aggregate distributions of $1.4 billion on our common units, subordinated units and related general partner units including IDRs.

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.

The amount of cash that we can distribute on our common units principally will depend upon the amount of cash that we generate from our existing operations, which will be based on, among other things:

- performance by counterparties of their obligations under the SPAs;
- performance by SPL of its obligations under the SPAs;
- performance by counterparties of their obligations under the TUAs;
- performance by SPLNG of its obligations under the TUAs;
- performance by, and the level of cash receipts received from, Cheniere Marketing under the amended and restated variable capacity rights agreement; and
- the level of our operating costs, including payments to our general partner and its affiliates.

In addition, the actual amount of cash that we will have available for distribution will depend on other factors such as:

- the restrictions contained in our debt agreements and our debt service requirements, including our ability to pay distributions under our credit facilities and the ability of SPL to pay distributions to us under its working capital facility and senior notes;
- the costs and capital requirements of acquisitions, if any;
- fluctuations in our working capital needs;
- our ability to borrow for working capital or other purposes; and
- the amount, if any, of cash reserves established by our general partner.

We may not be successful in our efforts to maintain or increase our cash available for distribution to cover the distributions on our units. Any reductions in distributions to our unitholders because of a shortfall in cash flow or other events could result in a decrease of the quarterly distribution on our common units below the initial quarterly distribution. Any portion of the initial quarterly distribution that is not distributed on our common units will accrue and be paid to the common unitholders in accordance with our partnership agreement, if at all.

We will need to refinance, extend or otherwise satisfy our substantial indebtedness, and principal amortization or other terms of our future indebtedness could limit our ability to pay or increase distributions to our unitholders.

As of December 31, 2020, we had $17.8 billion of total debt outstanding on a consolidated basis (before unamortized premium, discount and debt issuance costs). We anticipate refinancing of consolidated indebtedness in the future, which could be at higher interest rates and have different maturity dates and more restrictive covenants than our current outstanding indebtedness. $1.0 billion will mature in 2022, $1.5 billion will mature in 2023, $2.0 billion will mature in 2024, $3.5 billion will mature in 2025, approximately $9.0 billion will mature between 2026 and 2030 and approximately $0.8 billion will mature in 2037. We are not generally required to make principal payments on any of our long-term indebtedness prior to maturity. Our ability to refinance, extend or otherwise satisfy our indebtedness, and the principal amortization, interest rate and other terms on which we may be able to do so, will depend, among other things, on our then contracted or otherwise anticipated future cash flows available for debt service. SPLNG's TUAs with Total and Chevron will expire in 2029 unless extended and SPL's SPAs will expire beginning in 2033 unless extended. Our ability to pay or increase distributions to our unitholders in future years could be limited by principal amortization, interest rate or other terms of our future indebtedness. If we are unable to refinance, extend or otherwise satisfy our debt as it matures, that would have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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 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 the agreements governing its indebtedness generally until, among other requirements, deposits are made into debt service reserve accounts and a debt service coverage ratio of 1.25:1.00 is satisfied.

If our subsidiaries are unable to pay distributions to us or incur indebtedness as a result of the foregoing restrictions in agreements governing their indebtedness, we may be inhibited in our ability to pay or increase distributions to our unitholders.

Restrictions in agreements governing our subsidiaries' indebtedness may prevent our subsidiaries from engaging in certain beneficial transactions.

In addition to restrictions on the ability of 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.

Management fees and cost reimbursements due to our general partner and its affiliates will reduce cash available to pay distributions to our unitholders.

We pay significant management fees to our general partner and its affiliates and reimburse them for expenses incurred on our behalf, which reduces our cash available for distribution to our unitholders. See Note 14—Related Party Transactions of our Notes to Consolidated Financial Statements for a description of these fees and expenses. Our general partner and its affiliates will also be entitled to reimbursement for all other direct expenses that they incur on our behalf. The payment of fees to our general partner and its affiliates and the reimbursement of expenses could adversely affect our ability to pay cash distributions to our unitholders.

The amount of cash that we have available for distributions to our unitholders will depend primarily on our cash flow and not solely on profitability.

The amount of cash that we will have available for distributions will depend primarily on our cash flow, including cash reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses, and we may not make cash distributions during periods when we record net income. Any reduction in the amount of cash available for distributions could impact our ability to pay quarterly distributions to our unitholders.

We may not be able to maintain or increase the distributions on our common units unless we are able to make accretive acquisitions or implement accretive capital expansion projects, which may require us to obtain one or more sources of funding.

We may not be able to make accretive acquisitions or implement accretive capital expansion projects, including our liquefaction facilities, that would result in sufficient cash flow to allow us to maintain or increase common unitholder distributions. To fund acquisitions or capital expansion projects, we will need to pursue a variety of sources of funding, including debt and/or equity financings. Our ability to obtain these or other types of financing will depend, in part, on factors beyond our control, such as our ability to obtain commitments from users of the facilities to be acquired or constructed, the status of various debt and equity markets at the time financing is sought and such markets' view of our industry and prospects at such time. Any restrictive lending conditions in the U.S. credit markets may make it more time consuming and expensive for us to obtain financing, if we can obtain such financing at all. Accordingly, we may not be able to obtain financing for acquisitions or capital expansion projects on terms that are acceptable to us, if at all.

Risks Relating to an Investment in Us and Our Common Units

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. Please read "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 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.

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.

Cheniere and its affiliates are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. Cheniere may acquire, construct or dispose of its liquefaction project at Corpus Christi, Texas, its pipeline or any other assets without any obligation to offer us the opportunity to purchase or construct any of those assets, other than, in certain circumstances under an investors rights agreement with Blackstone CQP Holdco, its liquefaction project at Corpus Christi, Texas. In addition, under our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to Cheniere and its affiliates. As a result, neither Cheniere nor any of its affiliates will have any obligation to present new business opportunities to us, they may take advantage of such opportunities themselves and they may enter into commercial arrangements with respect to the liquefaction project at Corpus Christi, Texas that might otherwise have been entered into with respect to Train 6. Cheniere also has significantly greater resources and experience than we have, which may make it more difficult for us to compete with Cheniere and its affiliates with respect to commercial activities or acquisition candidates.

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;
- 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 proceeding 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.

Even if our unitholders are dissatisfied, they cannot initially remove our general partner without its consent.

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.

Control of our general partner may be transferred to a third party without unitholder consent.

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.

Our partnership agreement restricts the voting rights of unitholders (other than our general partner and its affiliates) owning 20% or more of any class of our units.

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.

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.

We may issue additional units without approval of our unitholders, which would dilute their ownership interest in us.

We may issue an unlimited number of limited partner interests of any type without limitation of any kind. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available per unit to pay distributions may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

The market price of our common units has fluctuated significantly in the past and is likely to fluctuate in the future. Our unitholders could lose all or part of their investment.

The market price of our common units has historically experienced and may continue to experience volatility. For example, during the three-year period ended December 31, 2020, the market price of our common units ranged between $17.75 and $49.30. Such fluctuations may continue as a result of a variety of factors, some of which are beyond our control, including:

- our quarterly distributions;
- domestic and worldwide supply of and demand for natural gas and corresponding fluctuations in the price of natural gas;
- fluctuations in our quarterly or annual financial results or those of other companies in our industry;
- issuance of additional equity securities which causes further dilution to our unitholders;
- sales of a high volume of our common units by our unitholders;
- operating and unit price performance of companies that investors deem comparable to us;
- events affecting other companies that the market deems comparable to us;
- changes in government regulation or proposals applicable to us;
- actual or potential non-performance by any customer or a counterparty under any agreement;
- announcements made by us or our competitors of significant contracts;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general conditions in the industries in which we operate;
- general economic conditions;

- the failure of securities analysts to cover our common units or changes in financial or other estimates by analysts;
- changes in investor sentiment regarding the energy industry and fossil fuels; and
- other factors described in these "Risk Factors."

In addition, the United States securities markets have experienced significant price and volume fluctuations. These fluctuations have often been unrelated to the operating performance of companies in these markets. Market fluctuations and broad market, economic and industry factors may negatively affect the price of our common units, regardless of our operating performance. If we were to be the object of securities class litigation as a result of volatility in our common unit price or for other reasons, it could result in substantial diversion of our management's attention and resources, which could negatively affect our financial results.

Affiliates of our general partner or affiliates of Blackstone or 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, 2020, 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. If we were treated as a corporation for federal income 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.

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 income tax purposes, then the initial quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, 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 any such taxes 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 additional amounts of entity-level taxation for state or local income tax purposes, the initial quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Members of Congress have frequently proposed and considered substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships or an investment in our common units, including proposals that would eliminate our ability to qualify for partnership tax treatment.

In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership in the future.

Any changes to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception to be treated as a partnership for U.S. federal income tax purposes or otherwise adversely affect us. We are unable to predict whether any changes, or other proposals, will ultimately be enacted. Any such changes or interpretations thereof could negatively impact the value of an investment in our common units. Unitholders are urged to consult with their own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on investments in our common units.

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 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 we may either pay the taxes directly to the IRS or elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes. If we bear such payment our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, 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 the new rules, our general partner may either pay the taxes (including any applicable penalties and interest) 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. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance 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 tax liability resulting from such audit adjustment, even if such unitholders did not own common 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.

Because our unitholders will be treated as partners to whom we will allocate taxable income, which could be different in amount from the cash that we distribute, our unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they do not receive any cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability which results from 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.

Unitholders may be subject to limitations on their ability to deduct interest expense incurred by us.

Our ability to deduct interest paid or accrued on our debt may be limited in certain circumstances. Should our ability to deduct business interest be limited, the amount of taxable income allocated to our unitholders in the taxable year in which the limitation is in effect may increase. In certain circumstances, a unitholder may be able to utilize a portion of a business interest deduction subject to this limitation in future taxable years. Unitholders should consult their tax advisors regarding the impact of this business interest deduction limitation on an investment in our units.

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, the transferee is generally required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person. While the determination of a unitholder's "amount realized" generally includes any decrease of a partner's share of the partnership's liabilities, recently issued 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 transferor, and thus will be determined without regard to any decrease in that partner's share of a publicly traded partnership's liabilities. The Treasury regulations further provide that withholding on a transfer of an interest in a publicly traded partnership will not be imposed on a transfer that occurs prior to January 1, 2022, 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.

We will treat each holder of our common units as having the same tax benefits without regard to the actual common units held. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we adopt depreciation and amortization positions that may not conform with all aspects of applicable Treasury Regulations.

A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of those tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to a unitholder's tax returns.

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.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder, and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult with their tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and loaning their common units.

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. 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. We continue to coordinate with PHMSA and FERC to address the matters relating to the February 2018 leak, including repair approach and related analysis. We do not expect that the Consent Order and related analysis, repair and remediation 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 19, 2021, 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 "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 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. SELECTED FINANCIAL DATA

Selected financial data set forth below are derived from our audited Consolidated Financial Statements for the periods indicated (in millions, except per unit data). The financial data should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations and our Consolidated Financial Statements and the accompanying notes thereto included elsewhere in this report.

	Year Ended December 31,				
	2020	2019	2018	2017	2016
Consolidated Statement of Income Data:					
Revenues (including transactions with affiliates)	$ 6,167	$ 6,838	$ 6,426	$ 4,304	$ 1,100
Income from operations	2,125	2,040	1,979	1,156	250
Interest expense, net of capitalized interest	(909)	(885)	(733)	(614)	(357)
Net income (loss)	1,183	1,175	1,274	490	(171)
Common Unit Data:					
Net income (loss) per common unit	$ 2.32	$ 2.25	$ 2.51	$ (1.32)	$ (0.20)
Weighted average units outstanding	399.3	348.6	348.6	178.5	57.1

	December 31,				
	2020	2019	2018	2017	2016
Consolidated Balance Sheet Data:					
Property, plant and equipment, net	$ 16,723	$ 16,368	$ 15,390	$ 15,139	$ 14,158
Total assets	19,145	19,384	17,974	17,553	15,542
Current debt, net	—	—	—	—	224
Long-term debt, net	17,580	17,579	16,066	16,046	14,209

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. Our discussion and analysis includes the following subjects:

- Overview of Business
- Overview of Significant Events
- Impact of COVID-19 and Market Environment
- Results of Operations
- Liquidity and Capital Resources
- Contractual Obligations
- Off-Balance Sheet Arrangements
- Summary of Critical Accounting Estimates
- Recent Accounting Standards

Overview of Business

We are a publicly traded Delaware limited partnership formed by Cheniere in 2006. 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.

The Sabine Pass LNG terminal is located in Cameron Parish, Louisiana, on the Sabine-Neches Waterway less than four miles from the Gulf Coast. Through our subsidiary, SPL, we are currently operating five natural gas liquefaction Trains and are constructing one additional Train that is expected to be substantially completed in the second half of 2022, for a total production capacity of approximately 30 mtpa of LNG (the "Liquefaction Project") at the Sabine Pass LNG terminal, one of the largest LNG production facilities in the world. Through our subsidiary, SPLNG, we own and operate regasification facilities at the Sabine Pass LNG terminal, which includes pre-existing infrastructure of five LNG storage tanks with aggregate capacity of approximately 17 Bcfe, two existing marine berths and one under construction that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4 Bcf/d. We also own a 94-mile pipeline through our subsidiary, CTPL, that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines.

Overview of Significant Events

Our significant events since January 1, 2020 and through the filing date of this Form 10-K include the following:

Strategic

- In August 2020, SPL 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 operational 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.

Operational

- As of February 19, 2021, more than 1,175 cumulative LNG cargoes totaling over 80 million tonnes of LNG have been produced, loaded and exported from the Liquefaction Project.

Financial

- In February 2021, SPL entered into a note purchase agreement for the sale of approximately $147 million aggregate principal amount of 2.95% Senior Secured Notes due 2037 (the "2.95% SPL 2037 Senior Secured Notes") on a private placement basis. The 2.95% SPL 2037 Senior Secured Notes are expected to be issued in December 2021, and the net proceeds are expected to be used to refinance a portion of SPL's outstanding Senior Secured Notes due 2022. The 2.95% SPL 2037 Senior Secured Notes will be fully amortizing, with a weighted average life of over 10 years.
- 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 were met under the terms of our 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.
- In May 2020, SPL issued an aggregate principal amount of $2.0 billion of 4.500% Senior Secured Notes due 2030 (the "2030 SPL Senior Notes"). Net proceeds of the offering, along with available cash, were used to redeem all of SPL's outstanding 5.625% Senior Secured Notes due 2021 (the "2021 SPL Senior Notes").
- In March 2020, SPL entered into a $1.2 billion Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement (the "2020 SPL Working Capital Facility"), which refinanced its previous working capital facility, reduced the interest rate and extended the maturity date to March 2025.
- In February 2021, Fitch Ratings upgraded the outlook of SPL's senior secured notes rating to positive from stable.

Impact of COVID-19 and Market Environment

The LNG business environment in 2020 was impacted by the coronavirus pandemic and its economic ramifications. Lockdown measures across the globe reduced economic activity and resulted in lower energy needs throughout most of the year. However, LNG demand proved relatively resilient as compared to other hydrocarbons, showing an annual gain of approximately 1.4%, or 5 MT, to 364 MT in 2020. While the economic recovery in Asia, and particularly in China, lifted LNG demand in the second half of the year, uncertainty about the pandemic's track remains the primary near-term risk to LNG trade. A slow return towards normal is expected to occur in the coming months, depending on the speed of vaccine rollout within regions, vaccine effectiveness against mutations and the speed and shape of economic recovery across the LNG importing nations. The continued improvements in global economic indicators seen in the fourth quarter is encouraging especially in China, which represents one of the key countries for LNG demand growth.

In the fourth quarter of 2020, natural gas and LNG spot prices significantly increased in line with the increase in economic activity and with seasonal norms. After falling to all-time lows in the second quarter, global LNG price benchmarks have made an impressive climb and exited the year at the highest levels since March 2019. As an example, the Dutch Title Transfer Facility ("TTF"), a virtual trading point for natural gas in the Netherlands, settled December at $5.08/MMBtu, $3.94/MMBtu higher than its June 2020 settlement. Similarly, the Japan Korea Marker ("JKM"), an LNG benchmark price assessment for spot physical cargoes delivered ex-ship into certain key markets in Asia, settled December at $6.90/MMBtu, which is $4.84/MMBtu higher than its all-time low July 2020 settlement. Record-low winter temperatures, supply outages and transportation bottlenecks contributed to drive JKM prices up to all-time highs by mid-January 2021. In a projection published in July 2020, IHS Markit estimated LNG demand to reach 383 MT in 2021, implying a return to higher growth in 2021.

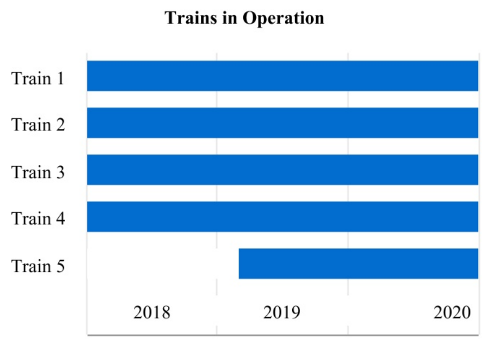
We have limited exposure to the fluctuations in oil and LNG spot prices as we have contracted a significant portion of our LNG production capacity under long-term sale and purchase agreements linked to a Henry Hub price. For this reason, we do not expect price fluctuations to have a material impact on our forecasted financial results for 2021.

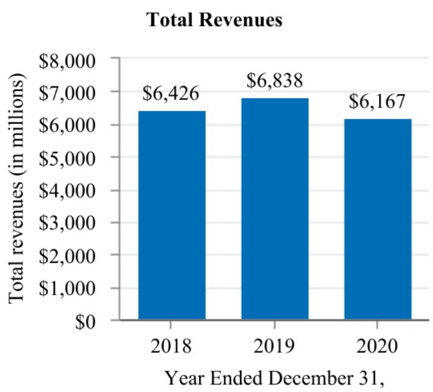
The number of LNG cargoes for which customers notified us that they would not take delivery has reduced from this summer, a sign that the market is continuing to adjust and rebalance toward equilibrium. We do not expect these events to have a material adverse impact on our forecasted financial results for 2021, due to the highly contracted nature of our business and the fact that customers continue to be obligated to pay fixed fees for cargoes with respect to which they have exercised their contractual right to cancel. As such, 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 experienced decreased revenues during the year ended December 31, 2020 associated with LNG cargoes that were scheduled for delivery for which customers notified us that they would not take delivery of such cargoes.

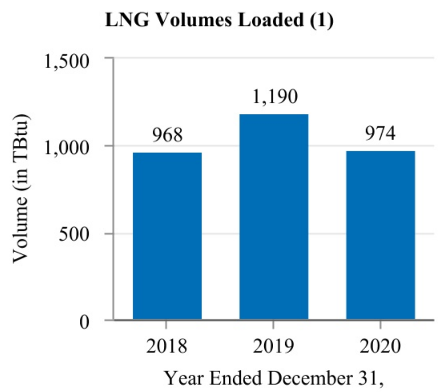
In addition, in response to the COVID-19 pandemic, Cheniere has modified certain business and workforce practices to protect the safety and welfare of its employees who continue to work at its facilities and offices worldwide, as well as implemented certain mitigation efforts to ensure business continuity. In March 2020, Cheniere began consulting with a medical advisor, and implemented social distancing through revised shift schedules, work from home policies and designated remote work locations where appropriate, restricted non-essential business travel and began requiring self-screening for employees and contractors. In April 2020, Cheniere began providing temporary housing for its workforce for our facilities, implemented temperature testing, incorporated medical and social workers to support employees, implemented prior self-isolation and screening for temporary housing and implemented marine operations with zero contact during loading activities. These measures have resulted in increased costs. While response measures continue to evolve and in most cases have moderated or ceased, we expect Cheniere to incur incremental operating costs associated with business continuity and protection of its workforce until the risks associated with the pandemic diminish. We have incurred approximately $36 million of such costs during the year ended December 31, 2020.

Results of Operations

The following charts summarize the number of Trains that were in operation during the years ended December 31, 2020, 2019 and 2018 and total revenues and total LNG volumes loaded (including both operational and commissioning volumes) for the respective periods:







(1) The year ended December 31, 2020 excludes 17 TBtu that was loaded at our affiliate's facility.

Our consolidated net income was $1.2 billion, or $2.32 per common unit (basic and diluted), for the year ended December 31, 2020, compared to $1.2 billion, or $2.25 per common unit (basic and diluted), for the year ended December 31, 2019. Although net income stayed relatively consistent between the periods, there were increased margins due to lower pricing of natural gas feedstock and additional LNG volume available to be sold from an additional Train that has reached substantial completion between the periods, a portion of which the customers elected not to take delivery but were required to pay a fixed fee with respect to the contracted volumes, partially offset by increases in (1) loss on modification or extinguishment of debt incurred in conjunction with the refinancing of the 2021 SPL Senior Notes, (2) interest expense, net of capitalized interest and (3) depreciation and amortization expense.

Our consolidated net income was $1.3 billion, or $2.51 per common unit (basic and diluted), in the year ended December 31, 2018.The $99 million decrease in net income for the year ended December 31, 2019 from the comparable 2018 period was primarily a result of an increase in (1) operating and maintenance expense, (2) interest expense, net of capitalized interest and (3) depreciation and amortization expense, partially offset by increased gross margins due to higher volumes of LNG sold but decreased pricing on LNG.

We enter into derivative instruments to manage our exposure to commodity-related marketing and price risk. Derivative instruments are reported at fair value on our Consolidated Financial Statements. In some cases, the underlying transactions economically hedged receive accrual accounting treatment, whereby revenues and expenses are recognized only upon delivery, receipt 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, use of derivative instruments may increase the volatility of our results of operations based on changes in market pricing, counterparty credit risk and other relevant factors.

Revenues

	Year Ended December 31,				
(in millions, except volumes)	**2020**	**2019**	**Change**	**2018**	**Change**
LNG revenues	$ 5,195	$ 5,211	$ (16)	$ 4,827	$ 384
LNG revenues—affiliate	662	1,312	(650)	1,299	13
Regasification revenues	269	266	3	261	5
Other revenues	41	49	(8)	39	10
Total revenues	$ 6,167	$ 6,838	$ (671)	$ 6,426	$ 412
LNG volumes recognized as revenues (in TBtu) (1)	991	1,180	(189)	955	225

(1) Excludes volume associated with cargoes for which customers notified us that they would not take delivery and includes volume that was loaded at our affiliate's facility.

2020 vs. 2019 and 2019 vs. 2018

Total revenues decreased during the year ended December 31, 2020 from the comparable 2019 period, primarily as a result of decreased volumes recognized as revenues between the periods due to LNG cargoes for which customers notified us that they would not take delivery, although the decrease due to volume was partially offset by the revenues associated with such cargoes. During the year ended December 31, 2020, we recognized $553 million in such revenues. LNG revenues—affiliate also decreased during the year ended December 31, 2020 from the comparable periods due to less sales made to Cheniere Marketing at lower pricing. The increase in LNG revenues during the year ended December 31, 2019 from the comparable 2018 period was primarily attributable to the increased volume of LNG sold following the achievement of substantial completion of the Trains, partially offset by decreased revenues per MMBtu. We expect our LNG revenues to increase in the future upon Train 6 of the Liquefaction Project becoming operational.

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, 2019 and 2018, we realized offsets to LNG terminal costs of $48 million corresponding to 10 TBtu of LNG and $94 million corresponding to 13 TBtu of LNG, respectively, that were related to the sale of commissioning cargoes. We did not realize any offsets to LNG terminal costs during the year ended December 31, 2020.

Also included in LNG revenues are sales of unutilized natural gas procured for the liquefaction process and gains and losses from derivative instruments, which include the realized value associated with a portion of derivative instruments that settle through physical delivery. We recognized revenues of $255 million, $150 million and $151 million during the years ended December 31, 2020, 2019 and 2018, respectively, related to these transactions.

Operating costs and expenses

(in millions)	Year Ended December 31, 2020	2019	Change	2018	Change
Cost of sales	$ 2,505	$ 3,374	$ (869)	$ 3,403	$ (29)
Cost of sales—affiliate	77	7	70	—	7
Operating and maintenance expense	629	632	(3)	409	223
Operating and maintenance expense—affiliate	152	138	14	117	21
Operating and maintenance expense—related party	13	—	13	—	—
Development expense	—	—	—	2	(2)
General and administrative expense	14	11	3	11	—
General and administrative expense—affiliate	96	102	(6)	73	29
Depreciation and amortization expense	551	527	24	424	103
Impairment expense and loss on disposal of assets	5	7	(2)	8	(1)
Total operating costs and expenses	$ 4,042	$ 4,798	$ (756)	$ 4,447	$ 351

2020 vs. 2019 and 2019 vs. 2018

Our total operating costs and expenses decreased during the year ended December 31, 2020 from the year ended December 31, 2019, primarily as a result of decreased cost of sales from lower volumes and pricing of natural gas feedstock. Total operating costs and expenses increased during the year ended December 31, 2019 from the year ended December 31, 2018 primarily as a result of additional Trains that were operating between the periods. During the year ended December 31, 2019, we further incurred increased TUA reservation charges paid to SPLNG and to Total Gas & Power North America, Inc. ("Total") from payments under the partial TUA assignment agreement and increased third-party service and maintenance costs from turnaround and related activities at the Liquefaction Project.

Cost of sales includes costs incurred directly for the production and delivery of LNG from the Liquefaction Project, to the extent those costs are not utilized for the commissioning process. Cost of sales decreased during the year ended December 31, 2020 from the comparable period in 2019 primarily due to decreases in both the volumes and pricing of natural gas feedstock. Partially offsetting these decreases was increased losses from commodity derivatives to secure natural gas feedstock for the Liquefaction Project, primarily due to an unfavorable shift in long-term forward prices relative to our hedged position and increases in costs associated with a portion of derivative instruments that settle through physical delivery. Cost of sales decreased during the year ended December 31, 2019 from the comparable period in 2018 due to increased derivative gains from an increase in fair value of the derivatives associated with economic hedges to secure natural gas feedstock for the Liquefaction Project, primarily due to a favorable shift in long-term forward prices. Partially offsetting this increase was a decrease in pricing of natural gas feedstock between the years, which in turn was partially offset by increased volumes of natural gas feedstock for our LNG sales as a result of substantial completion of Train 5 of the Liquefaction Project. Cost of sales also includes variable transportation and storage costs and other costs to convert natural gas into LNG.

Cost of sales—affiliate increased during the year ended December 31, 2020 for the cost of cargoes procured from our affiliate to fulfill our commitments to our long-term customers during operational interruption, such as the one we experienced during the shutdown of the Liquefaction Project during Hurricane Laura in September 2020.

Operating and maintenance expense (including affiliate) primarily includes costs associated with operating and maintaining the Liquefaction Project. The increase in operating and maintenance expense (including affiliates) during the year ended December 31, 2020 from the comparable 2019 and 2018 periods was primarily related to increased natural gas transportation and storage capacity demand charges paid to third parties from operating Train 5 of the Liquefaction Project following its substantial completion and increased TUA reservation charges due to Total under the partial TUA assignment agreement. In addition, operating and maintenance expense (including affiliate) was higher in 2019 due to increase in third-party service and maintenance costs associated with turnaround activities at the Liquefaction Project during 2019 and higher in 2020 due to costs incurred in response to the COVID-19 pandemic, as further described above in *Impact of COVID-19 and Market Environment*. Operating and maintenance expense (including affiliates) also includes payroll and benefit costs of operations personnel, insurance and regulatory costs and other operating costs.

Depreciation and amortization expense increased during each of the years ended December 31, 2020 and 2019 as a result of an increase in operational Trains, as the related assets began depreciating upon reaching substantial completion.

Other expense

	Year Ended December 31,									
(in millions)	2020		2019		Change		2018		Change	
Interest expense, net of capitalized interest	$	909	$	885	$	24	$	733	$	152
Loss on modification or extinguishment of debt		43		13		30		12		1
Derivative gain, net		—		—		—		(14)		14
Other income, net		(8)		(31)		23		(26)		(5)
Other income—affiliate		(2)		(2)		—		—		(2)
Total other expense	$	942	$	865	$	77	$	705	$	160

2020 vs. 2019 and 2019 vs. 2018

Interest expense, net of capitalized interest, increased during the year ended December 31, 2020 from the comparable period in 2019 primarily as a result of higher interest costs as a result of the issuance of the $1.5 billion of 4.500% Senior Notes due 2029 (the “2029 CQP Senior Notes”) in September 2019. This increase was partially offset by an increase in the portion of total interest costs that was eligible for capitalization as the construction of Train 6 commenced in May 2019. Interest expense, net of capitalized interest, increased during the year ended December 31, 2019 from the comparable 2018 period primarily as a result of a decrease in the portion of total interest costs that could be capitalized as additional Trains of the Liquefaction Project completed construction between the periods. During the years ended December 31, 2020, 2019 and 2018, we incurred $1,005 million, $972 million and $936 million of total interest cost, respectively, of which we capitalized $96 million, $87 million and $203 million, respectively, which was primarily related to interest costs incurred to construct the remaining assets of the Liquefaction Project.

Loss on modification or extinguishment of debt increased during the year ended December 31, 2020 from the comparable 2019 and 2018 periods. The loss on modification or extinguishment of debt recognized in each of the years included the incurrence fees paid to lenders, third party fees and write off of unamortized debt issuance costs recognized upon refinancing our credit facilities with senior notes, refinancing of senior notes or upon amendment and restatement of our credit facilities.

Derivative gain, net decreased during the years ended December 31, 2020 and 2019 compared to the year ended December 31, 2018, as we no longer held interest rate swaps used to hedge a portion of the variable interest payments on our credit facilities, as they were terminated in October 2018.

Other expense, net decreased during the year ended December 31, 2020 from the comparable periods in 2019 and 2018, due to a decrease in interest income earned on our cash and cash equivalents.

Liquidity and Capital Resources

The following table provides a summary of our liquidity position at December 31, 2020 and 2019 (in millions):

	December 31,			
	2020		2019	
Cash and cash equivalents	$	1,210	$	1,781
Restricted cash designated for the Liquefaction Project		97		181
Available commitments under the following credit facilities:				
$1.2 billion Amended and Restated SPL Working Capital Facility (“2015 SPL Working Capital Facility”)		—		786
2020 SPL Working Capital Facility		787		—
CQP Credit Facilities executed in 2019 (“2019 CQP Credit Facilities”)		750		750

CQP Senior Notes

The $1.5 billion of 5.250% Senior Notes due 2025 (the "2025 CQP Senior Notes"), $1.1 billion of 5.625% Senior Notes due 2026 (the "2026 CQP Senior Notes") and the 2029 CQP Senior Notes (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 Senior Notes are governed by the same base indenture (the "CQP Base Indenture"). The 2025 CQP Senior Notes are further governed by the First Supplemental Indenture, the 2026 CQP Senior Notes are further governed by the Second Supplemental Indenture and the 2029 CQP Senior Notes are further governed by the Third Supplemental Indenture. The indentures governing the CQP Senior Notes contain terms and events of default and certain covenants that, among other things, limit our ability and the CQP Guarantors' ability to incur liens and sell assets, enter into transactions with affiliates, enter into sale-leaseback transactions and consolidate, merge or sell, lease or otherwise dispose of all or substantially all of the applicable entity's properties or assets.

At any time prior to October 1, 2021 for the 2026 CQP Senior Notes and October 1, 2024 for the 2029 CQP Senior Notes, we may redeem all or a part of the applicable CQP Senior Notes at a redemption price equal to 100% of the aggregate principal amount of the CQP Senior Notes redeemed, plus the "applicable premium" set forth in the respective indentures governing the CQP Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. In addition, at any time prior to October 1, 2021 for the 2026 CQP Senior Notes and October 1, 2024 for the 2029 CQP Senior Notes, we may redeem up to 35% of the aggregate principal amount of the CQP Senior Notes with an amount of cash not greater than the net cash proceeds from certain equity offerings at a redemption price equal to 105.625% of the aggregate principal amount of the 2026 CQP Senior Notes and 104.5% of the aggregate principal amount of the 2029 CQP Senior Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption. We also may at any time through the maturity date of October 1, 2025 for the 2025 CQP Senior Notes, October 1, 2021 through the maturity date of October 1, 2026 for the 2026 CQP Senior Notes and October 1, 2024 through the maturity date of October 1, 2029 for the 2029 CQP Senior Notes, redeem the CQP Senior Notes, in whole or in part, at the redemption prices set forth in the respective indentures governing the CQP Senior Notes.

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 our 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 to the same extent as such obligations under the 2019 CQP Credit Facilities. The obligations under the 2019 CQP Credit Facilities are secured on a first-priority basis (subject to permitted encumbrances) with liens on substantially all our existing and future tangible and intangible assets and our rights and the rights of the CQP Guarantors and equity interests in the CQP Guarantors (except, in each case, for certain excluded properties set forth in the 2019 CQP Credit Facilities). The liens securing the CQP Senior Notes, if applicable, will be shared equally and ratably (subject to permitted liens) with the holders of other senior secured obligations, which include the 2019 CQP Credit Facilities obligations and any future additional senior secured debt obligations.

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 Cheniere Partners ("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. See Sabine Pass LNG Terminal—SPL Senior Notes for additional detail on restrictions of Non-Guarantor debt.

Summarized Balance Sheets (in millions)	**December 31,**	
	2020	**2019**
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,210	$ 1,781
Accounts receivable from Non-Guarantors	46	43
Other current assets	42	33
Current assets—affiliate	137	145
Total current assets	1,435	2,002
Property, plant and equipment, net	2,493	2,533
Other non-current assets, net	117	122
Total assets	$ 4,045	$ 4,657
LIABILITIES		
Current liabilities		
Due to affiliates	$ 156	$ 158
Deferred revenue from Non-Guarantors	22	21
Deferred revenue—affiliate	—	1
Other current liabilities	100	111
Total current liabilities	278	291
Long-term debt, net	4,060	4,055
Other non-current liabilities	85	83
Non-current liabilities—affiliate	17	20
Total liabilities	$ 4,440	$ 4,449

Summarized Statement of Income (in millions)	**Year Ended December 31, 2020**
Revenues	$ 310
Revenues from Non-Guarantors	518
Total revenues	828
Operating costs and expenses	181
Operating costs and expenses—affiliate	194
Total operating costs and expenses	375
Income from operations	453
Net income	238

2019 CQP Credit Facilities

In May 2019, we entered into the 2019 CQP Credit Facilities, which consisted of the $750 million term loan ("CQP Term Facility"), which was prepaid and terminated upon issuance of the 2029 CQP Senior Notes in September 2019, and the $750 million revolving credit facility ("CQP Revolving Facility"). Borrowings under the 2019 CQP Credit Facilities will be used to fund the development and construction of Train 6 of the Liquefaction Project and for general corporate purposes, subject to a sublimit, and the 2019 CQP Credit Facilities are also available for the issuance of letters of credit. As of both December 31, 2020 and 2019, we had $750 million of available commitments and no letters of credit issued or loans outstanding under the 2019 CQP Credit Facilities.

The 2019 CQP Credit Facilities mature on May 29, 2024. Any outstanding balance may be repaid, in whole or in part, at any time without premium or penalty, except for interest rate breakage costs. The 2019 CQP Credit Facilities contain conditions precedent for extensions of credit, as well as customary affirmative and negative covenants, and limit our ability to make restricted payments, including distributions, to once per fiscal quarter and one true-up per fiscal quarter as long as certain conditions are satisfied.

The 2019 CQP Credit Facilities are unconditionally guaranteed and secured by a first priority lien (subject to permitted encumbrances) on substantially all of our and the CQP Guarantors' existing and future tangible and intangible assets and rights and equity interests in the CQP Guarantors (except, in each case, for certain excluded properties set forth in the 2019 CQP Credit Facilities).

Sabine Pass LNG Terminal

Liquefaction Facilities

The Liquefaction Project is one of the largest LNG production facilities in the world. We are currently operating five Trains and two marine berths at the Liquefaction Project, and are constructing one additional Train that is expected to be substantially completed in the second half of 2022, and a third marine berth. We have received authorization from the FERC to site, construct and operate Trains 1 through 6, as well as for the construction of the third marine berth. We have achieved substantial completion of the first five Trains of the Liquefaction Project and commenced commercial operating activities for each Train at various times starting in May 2016. The following table summarizes the project completion and construction status of Train 6 of the Liquefaction Project as of December 31, 2020:

	Train 6
Overall project completion percentage	77.6%
Completion percentage of:	
Engineering	99.0%
Procurement	99.9%
Subcontract work	54.9%
Construction	49.2%
Date of expected substantial completion	2H 2022

The following orders have been issued by the DOE authorizing the export of domestically produced LNG by vessel from the Sabine Pass LNG terminal:

- Trains 1 through 4—FTA countries and non-FTA countries through December 31, 2050, in an amount up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr of natural gas).
- Trains 1 through 4—FTA countries and non-FTA countries through December 31, 2050, in an amount up to a combined total of the equivalent of approximately 203 Bcf/yr of natural gas (approximately 4 mtpa).
- Trains 5 and 6—FTA countries and non-FTA countries through December 31, 2050, in an amount up to a combined total of 503.3 Bcf/yr of natural gas (approximately 10 mtpa).

In December 2020, the DOE announced a new policy in which it would no longer issue short-term export authorizations separately from long-term authorizations. Accordingly, the DOE amended each of SPL's long-term authorizations to include short-term export authority, and vacated the short-term orders.

An application was filed in September 2019 seeking authorization to make additional exports from the Liquefaction Project to FTA countries for a 25-year term and to non-FTA countries for a 20-year term in an amount up to the equivalent of approximately 153 Bcf/yr of natural gas, for a total Liquefaction Project export capacity of approximately 1,662 Bcf/yr. The terms of the authorizations are requested to commence on the date of first commercial export from the Liquefaction Project of the volumes contemplated in the application. In April 2020, the DOE issued an order authorizing SPL to export to FTA countries related to this application, for which the term was subsequently extended through December 31, 2050, but has not yet issued an order authorizing SPL to export to non-FTA countries for the corresponding LNG volume. A corresponding application for authorization to increase the total LNG production capacity of the Liquefaction Project from the currently authorized level to approximately 1,662 Bcf/yr was also submitted to the FERC and is currently pending.

Customers

SPL has entered into fixed price long-term SPAs generally with terms of 20 years (plus extension rights) and with a weighted average remaining contract length of approximately 17 years (plus extension rights) with eight third parties for Trains 1 through 6 of the Liquefaction Project to make available an aggregate amount of LNG that is approximately 75% of the total production capacity from these Trains, potentially increasing up to approximately 85% after giving effect to an SPA that Cheniere has committed to provide to us. Under these SPAs, the customers will purchase LNG from SPL 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 approximately 115% of Henry Hub. The 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. We refer to the fee component that is applicable regardless of a cancellation or suspension of LNG cargo deliveries under the SPAs as the fixed fee component of the price under SPL's SPAs. We refer to the fee component that is applicable only in connection with LNG cargo deliveries as the variable fee component of the price under SPL's SPAs. The variable fees under SPL's SPAs were generally sized at the time of entry into each SPA with the intent to cover the costs of gas purchases and transportation and liquefaction fuel to produce the LNG to be sold under each such SPA. 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.

In aggregate, the annual fixed fee portion to be paid by the third-party SPA customers is approximately $2.9 billion for Trains 1 through 5. After giving effect to an SPA that Cheniere has committed to provide to SPL, the annual fixed fee portion to be paid by the third-party SPA customers would increase to at least $3.3 billion, which is expected to occur upon the date of first commercial delivery of Train 6.

In addition, Cheniere Marketing has agreements with SPL to purchase: (1) at Cheniere Marketing's option, any LNG produced by SPL in excess of that required for other customers and (2) up to 30 cargoes scheduled for delivery in 2021 at a price of 115% of Henry Hub plus $0.728 per MMBtu.

Natural Gas Transportation, Storage and Supply

To ensure SPL is able to transport adequate natural gas feedstock to the Sabine Pass LNG terminal, it has entered into transportation precedent and other agreements to secure firm pipeline transportation capacity with CTPL and third-party pipeline companies. SPL has entered into firm storage services agreements with third parties to assist in managing variability in natural gas needs for the Liquefaction Project. SPL has also entered into enabling agreements and long-term natural gas supply contracts with third parties in order to secure natural gas feedstock for the Liquefaction Project. As of December 31, 2020, SPL had secured up to approximately 4,950 TBtu of natural gas feedstock through long-term and short-term natural gas supply contracts with remaining terms that range up to 10 years, a portion of which is subject to conditions precedent.

Construction

SPL entered into lump sum turnkey contracts with Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") for the engineering, procurement and construction of Trains 1 through 6 of the Liquefaction Project, under which Bechtel charges a lump sum for all work performed and generally bears project cost, schedule and performance risks unless certain specified events occur, in which case Bechtel may cause SPL to enter into a change order, or SPL agrees with Bechtel to a change order.

The total contract price of the EPC contract for Train 6 of the Liquefaction Project is approximately $2.5 billion, including estimated costs for the third marine berth that is currently under construction. As of December 31, 2020, we have incurred $1.9 billion under this contract.

Regasification Facilities

The Sabine Pass LNG terminal has operational regasification capacity of approximately 4 Bcf/d and aggregate LNG storage capacity of approximately 17 Bcfe. Approximately 2 Bcf/d of the regasification capacity at the Sabine Pass LNG terminal has been reserved under two long-term third-party TUAs, under which SPLNG's customers are required to pay fixed monthly fees, whether or not they use the LNG terminal. Each of Total and Chevron U.S.A. Inc. ("Chevron") has reserved approximately 1 Bcf/d of regasification capacity and 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 Total's obligations under its TUA up to $2.5 billion, subject to certain exceptions, and Chevron Corporation has guaranteed Chevron's obligations under its TUA up to 80% of the fees payable by Chevron.

The remaining approximately 2 Bcf/d of capacity has been reserved under a TUA by SPL. 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 Total, whereby upon substantial completion of Train 5 of the Liquefaction Project, SPL gained access to substantially all of Total's capacity and other services provided under Total's 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, permit SPL to more flexibly manage its LNG storage capacity and accommodate the development of Train 6. Notwithstanding any arrangements between Total and SPL, payments required to be made by Total to SPLNG will continue to be made by Total to SPLNG in accordance with its TUA. During the years ended December 31, 2020, 2019 and 2018, SPL recorded $129 million, $104 million and $30 million, respectively, as operating and maintenance expense under this partial TUA assignment agreement.

Under each of these TUAs, SPLNG is entitled to retain 2% of the LNG delivered to the Sabine Pass LNG terminal.

Capital Resources

We currently expect that SPL's capital resources requirements with respect to the Liquefaction Project will be financed through project debt and borrowings, cash flows under the SPAs and equity contributions from us. We believe that with the net proceeds of borrowings, available commitments under the 2020 SPL Working Capital Facility, 2019 CQP Credit Facilities, cash flows from operations and equity contributions from us, SPL will have adequate financial resources available to meet its currently anticipated capital, operating and debt service requirements with respect to Trains 1 through 6 of the Liquefaction Project. Additionally, SPLNG generates cash flows from the TUAs, as discussed above.

The following table provides a summary of our capital resources from borrowings and available commitments for the Sabine Pass LNG Terminal, excluding equity contributions to our subsidiaries and cash flows from operations (as described in *Sources and Uses of Cash*), at December 31, 2020 and 2019 (in millions):

	December 31,	
	2020	2019
Senior notes (1)	$ 17,750	$ 17,750
Credit facilities outstanding balance (2)	—	—
Letters of credit issued (3)	413	414
Available commitments under credit facilities (3)	1,537	1,536
Total capital resources from borrowings and available commitments (4)	$ 19,700	$ 19,700

(1) Includes SPL's 2021 SPL Senior Notes, 6.25% Senior Secured Notes due 2022, 5.625% Senior Secured Notes due 2023, 5.75% Senior Secured Notes due 2024, 5.625% Senior Secured Notes due 2025, 5.875% Senior Secured Notes due 2026 (the "2026 SPL Senior Notes"), 5.00% Senior Secured Notes due 2027 (the "2027 SPL Senior Notes"), 4.200% Senior Secured Notes due 2028 (the "2028 SPL Senior Notes"), 2030 SPL Senior Notes and 5.00% Senior Secured Notes due 2037 (the "2037 SPL Senior Notes") (collectively, the "SPL Senior Notes") and our CQP Senior Notes.

(2) Includes outstanding balances under the 2015 SPL Working Capital Facility, 2020 SPL Working Capital Facility and 2019 CQP Credit Facilities, inclusive of any portion of the 2020 SPL Working Capital Facility and 2019 CQP Credit Facilities that may be used for general corporate purposes.

(3) Consists of 2015 SPL Working Capital Facility, 2020 SPL Working Capital Facility and 2019 CQP Credit Facilities.

(4) Does not include equity contributions that may be available from Cheniere's borrowings and available cash and cash equivalents.

SPL Senior Notes

The SPL Senior Notes are governed by a common indenture (the "SPL Indenture") and the terms of the 2037 SPL Senior Notes are governed by a separate indenture (the "2037 SPL Senior Notes Indenture"). Both the SPL Indenture and the 2037 SPL Senior Notes Indenture contain terms and events of default and certain covenants that, among other things, limit SPL's ability and the ability of SPL's restricted subsidiaries to incur additional indebtedness or issue preferred stock, make certain investments or pay dividends or distributions on capital stock or subordinated indebtedness or purchase, redeem or retire capital stock, sell or transfer assets, including capital stock of SPL's restricted subsidiaries, restrict dividends or other payments by restricted subsidiaries, incur liens, enter into transactions with affiliates, dissolve, liquidate, consolidate, merge, sell or lease all or substantially all of SPL's assets and enter into certain LNG sales contracts. Subject to permitted liens, the SPL Senior 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 not make any distributions until, among other requirements, deposits are made into debt service reserve accounts as required and a debt service coverage ratio test of 1.25:1.00 is satisfied.

At any time prior to three months before the respective dates of maturity for each series of the SPL Senior Notes (except for the 2026 SPL Senior Notes, 2027 SPL Senior Notes, 2028 SPL Senior Notes, 2030 SPL Senior Notes and 2037 SPL Senior Notes, in which case the time period is six months before the respective dates of maturity), SPL may redeem all or part of such series of the SPL Senior Notes at a redemption price equal to the 'make-whole' price (except for the 2037 SPL Senior Notes, in which case the redemption price is equal to the "optional redemption" price) set forth in the respective indentures governing the SPL Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. SPL may also, at any time within three months of the respective maturity dates for each series of the SPL Senior Notes (except for the 2026 SPL Senior Notes, 2027 SPL Senior Notes, 2028 SPL Senior Notes, 2030 SPL Senior Notes and 2037 SPL Senior Notes, in which case the time period is within six months of the respective dates of maturity), redeem all or part of such series of the SPL Senior Notes at a redemption price equal to 100% of the principal amount of such series of the SPL Senior Notes to be redeemed, plus accrued and unpaid interest, if any, to the date of redemption.

Both the 2037 SPL Senior Notes Indenture and the SPL Indenture include restrictive covenants. SPL may incur additional indebtedness in the future, including by issuing additional notes, and such indebtedness could be at higher interest rates and have different maturity dates and more restrictive covenants than the current outstanding indebtedness of SPL, including the SPL Senior Notes and the 2020 SPL Working Capital Facility. Semi-annual principal payments for the 2037 SPL Senior Notes are due on March 15 and September 15 of each year beginning September 15, 2025 and are fully amortizing according to a fixed sculpted amortization schedule.

2015 SPL Working Capital Facility

In March 2020, SPL terminated the remaining commitments under the 2015 SPL Working Capital Facility. As of December 31, 2019, SPL had $786 million of available commitments, $414 million aggregate amount of issued letters of credit and no outstanding borrowings under the 2015 SPL Working Capital Facility.

2020 SPL Working Capital Facility

In March 2020, SPL entered into the 2020 SPL Working Capital Facility with aggregate commitments of $1.2 billion, which replaced the 2015 SPL Working Capital Facility. The 2020 SPL Working Capital Facility is intended to be used for loans to SPL, swing line loans to SPL and the issuance of letters of credit on behalf of SPL, primarily for (1) the refinancing of the 2015 SPL Working Capital Facility, (2) fees and expenses related to the 2020 SPL Working Capital Facility, (3) SPL and its future subsidiaries' gas purchase obligations and (4) SPL and certain of its future subsidiaries' general corporate purposes. SPL may, from time to time, request increases in the commitments under the 2020 SPL Working Capital Facility of up to $800 million. As of December 31, 2020, SPL had $787 million of available commitments, $413 million aggregate amount of issued letters of credit and no outstanding borrowings under the 2020 SPL Working Capital Facility.

The 2020 SPL Working Capital Facility matures on March 19, 2025, but may be extended with consent of the lenders. The 2020 SPL Working Capital Facility provides for mandatory prepayments under customary circumstances.

The 2020 SPL Working Capital Facility contains customary conditions precedent for extensions of credit, as well as customary affirmative and negative covenants. SPL is restricted from making certain distributions under agreements governing its indebtedness generally until, among other requirements, satisfaction of a 12-month forward-looking and backward-looking 1.25:1.00 debt service reserve ratio test. The obligations of SPL under the 2020 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 Notes.

Restrictive Debt Covenants

As of December 31, 2020, we and SPL were in compliance with all covenants related to our respective debt agreements.

LIBOR

The use of LIBOR is expected to be phased out by the end of 2021. It is currently unclear whether LIBOR will be utilized beyond that date or whether it will be replaced by a particular rate. We intend to continue working with our lenders to pursue any amendments to our debt agreements that are currently subject to LIBOR and will continue to monitor, assess and plan for the phase out of LIBOR.

Sources and Uses of Cash

The following table summarizes the sources and uses of our cash, cash equivalents and restricted cash for the years ended December 31, 2020, 2019 and 2018 (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,		
	2020	2019	2018
Sources of cash, cash equivalents and restricted cash:			
Net cash provided by operating activities	$ 1,751	$ 1,547	$ 1,874
Proceeds from issuances of debt	1,995	2,230	1,100
Other	4	5	—
	$ 3,750	$ 3,782	$ 2,974
Uses of cash, cash equivalents and restricted cash:			
Property, plant and equipment, net	$ (972)	$ (1,331)	$ (804)
Repayments of debt	(2,000)	(730)	(1,090)
Debt issuance and other financing costs	(35)	(35)	(8)
Debt extinguishment costs	(39)	(4)	(7)
Distributions to owners	(1,359)	(1,260)	(1,113)
Other	—	(1)	—
	(4,405)	(3,361)	(3,022)
Net increase (decrease) in cash, cash equivalents and restricted cash	$ (655)	$ 421	$ (48)

Operating Cash Flows

Our operating cash net inflows during the years ended December 31, 2020, 2019 and 2018 were $1,751 million, $1,547 million and $1,874 million, respectively. The $204 million increase in operating cash inflows in 2020 compared to 2019 was primarily related to decreased operating costs and expenses. The $327 million decrease in operating cash inflows in 2019 compared to 2018 was primarily related to increased operating costs and expenses, which were partially offset by increased cash receipts from the sale of LNG cargoes, as a result of an additional Train that was operating at the Liquefaction Project in 2019.

Proceeds from Issuance of Debt, Repayments of Debt, Debt Issuance and Other Financing Costs and Debt Extinguishment Costs

During the year ended December 31, 2020, we issued an aggregate principal amount of $2.0 billion of the 2030 SPL Senior Notes, which was used to redeem all of the outstanding 2021 SPL Senior Notes. We incurred $35 million of debt issuance costs primarily related to up-front fees paid and $39 million of debt extinguishment costs upon the closing of this transaction.

During the year ended December 31, 2019, we issued an aggregate principal amount of $1.5 billion in senior notes to prepay the outstanding indebtedness under our credit facilities. Borrowings of $730 million under our credit facilities were used for funding future capital expenditures in connection with the construction costs for the Liquefaction Project. We incurred $35 million of debt issuance costs primarily related to up-front fees paid and $4 million of debt extinguishment costs upon the closing of these transactions.

During the year ended December 31, 2018, we issued an aggregate principal amount of $1.1 billion in senior notes to prepay the outstanding indebtedness under our credit facilities. We incurred $8 million of debt issuance costs primarily related to up-front fees paid and $7 million of debt extinguishment costs upon the closing of this transaction.

Property, Plant and Equipment, net

Cash outflows for property, plant and equipment were primarily for the construction costs for the Liquefaction Project. These costs are capitalized as construction-in-process until achievement of substantial completion.

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, 2020, 2019 and 2018:

				Total Distribution (in millions)			
Date Paid	Period Covered by Distribution	Distribution Per Common Unit	Distribution Per Subordinated Unit	Common Units	Subordinated Units	General Partner Units	Incentive Distribution Rights
November 13, 2020	July 1 - September 30, 2010	$ 0.65	$ —	$ 315	$ —	$ 7	$ 25
August 14, 2020	April 1 - June 30, 2020	0.645	0.645	225	88	7	22
May 15, 2020	January 1 - March 31, 2020	0.64	0.64	223	86	7	20
February 14, 2020	October 1- December 31, 2019	0.63	0.63	220	85	6	18
November 14, 2019	July 1 - September 30, 2019	$ 0.62	$ 0.62	$ 216	$ 84	$ 6	$ 16
August 14, 2019	April 1 - June 30, 2019	0.61	0.61	213	83	6	15
May 15, 2019	January 1 - March 31, 2019	0.60	0.60	209	81	6	13
February 14, 2019	October 1 - December 31, 2018	0.59	0.59	206	80	6	12
November 14, 2018	July 1 - September 30, 2018	$ 0.58	$ 0.58	$ 202	$ 79	$ 5	$ 11
August 14, 2018	April 1 - June 30, 2018	0.56	0.56	195	76	6	7
May 15, 2018	January 1 - March 31, 2018	0.55	0.55	192	74	5	6
February 14, 2018	October 1 - December 31, 2017	0.50	0.50	174	68	5	1

On January 27, 2021, we declared a $0.655 distribution per common unit and the related distribution to our general partner and incentive distribution right holders that was paid on February 12, 2021 to unitholders of record as of February 8, 2021 for the period from October 1, 2020 to December 31, 2020.

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 were met under the terms of our 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.

Contractual Obligations

We are committed to make cash payments in the future pursuant to certain of our contracts. The following table summarizes certain contractual obligations in place as of December 31, 2020 (in millions):

	Payments Due By Period (1)				
	Total	2021	2022-2023	2024-2025	Thereafter
Debt (2)	$ 17,750	$ —	$ 2,500	$ 5,523	$ 9,727
Interest payments (2)	5,304	932	1,729	1,342	1,301
Operating lease obligations (3)	171	11	22	22	116
Purchase obligations: (4)					
Construction obligations (5)	625	362	263	—	—
Natural gas supply, transportation and storage service agreements (6)	9,889	2,949	3,079	1,651	2,210
Other purchase obligations (7)	2,221	199	398	392	1,232
Other non-current liabilities—affiliate (8)	19	2	5	5	7
Total	$ 35,979	$ 4,455	$ 7,996	$ 8,935	$ 14,593

(1) Agreements in force as of December 31, 2020 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2020.

(2) Based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2020. A discussion of our debt obligations can be found in Note 11—Debt of our Notes to Consolidated Financial Statements.

(3) Operating lease obligations primarily consist of land sites related to the Sabine Pass LNG terminal as further discussed in Note 12—Leases of our Notes to Consolidated Financial Statements.

(4) 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 only contracts for which conditions precedent have been met. As project milestones and other conditions precedent are achieved, our obligations are expected to increase accordingly. We include contracts for which we have an early termination option if the option is not expected to be exercised.

(5) Construction obligations primarily consist of the estimated remaining cost pursuant to our EPC contracts as of December 31, 2020 for projects with respect to which we have made an FID to commence construction. A discussion of these obligations can be found at Note 16—Commitments and Contingencies of our Notes to Consolidated Financial Statements.

(6) Pricing of natural gas supply agreements is based on estimated forward prices and basis spreads as of December 31, 2020. Natural gas transportation and storage service agreements includes $366 million in payments under agreements with a related party as discussed in Note 14—Related Party Transactions of our Notes to Consolidated Financial Statements.

(7) Other purchase obligations primarily relate to payments under SPL's partial TUA assignment agreement with Total as discussed in Note 13—Revenues from Contracts with Customers of our Notes to Consolidated Financial Statements.

(8) Other non-current liabilities—affiliate primarily relate to obligations to Cheniere Marketing related to the Cooperative Endeavor Agreement, as discussed in Note 14—Related Party Transactions of our Notes to Consolidated Financial Statements.

In addition, as of December 31, 2020, we had $413 million aggregate amount of issued letters of credit under our credit facilities.

Off-Balance Sheet Arrangements

As of December 31, 2020, we had no transactions that met the definition of off-balance sheet arrangements that may have a current or future material effect on our consolidated financial position or operating results.

Summary of Critical Accounting Estimates

The preparation of 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 Derivative Instruments

All derivative instruments, other than those that satisfy specific exceptions, are recorded at fair value. We record changes in the fair value of our derivative positions based on the value for which the derivative instrument could be exchanged between willing parties. If market quotes are not available to estimate fair value, management's best estimate of fair value is based on the quoted market price of derivatives with similar characteristics or determined through industry-standard valuation approaches. Such evaluations may involve significant judgment and the results are based on expected future events or conditions, particularly for those valuations using inputs unobservable in the market.

Our derivative instruments consist of financial commodity derivative contracts transacted in an over-the-counter market and physical commodity contracts. Valuation of our financial commodity derivative contracts is determined using observable commodity price curves and other relevant data.

Valuation of our physical commodity contracts 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 evaluating whether the respective market is available as pipeline infrastructure is developed. The fair value of our physical commodity contracts incorporates risk premiums related to the satisfaction of conditions precedent, such as completion and placement into service of relevant pipeline infrastructure to accommodate marketable physical gas flow. A portion of our physical commodity contracts require us to make critical accounting estimates that involve significant judgment, 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 Henry Hub basis spread for unobservable periods, liquidity, volatility and contract duration.

Gains and losses on derivative instruments are recognized in earnings. The ultimate fair value of our derivative instruments is uncertain, and we believe that it is reasonably possible that a change in the estimated fair value could occur in the near future as interest rates and commodity prices change.

Recent Accounting Standards

For descriptions 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 commissioning and 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, 2020		December 31, 2019	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
Liquefaction Supply Derivatives	$ (21)	$ 4	$ 24	$ 1

See Note 8—Derivative Instruments for additional details about our derivative instruments.

ITEM 8. CONSOLIDATED 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, 2020, 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, 2020, which is contained in this Form 10-K.

Management's Certifications

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

Cheniere Energy Partners, L.P.

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

By:	/s/ Jack A. Fusco	By:	/s/ Zach Davis
	Jack A. Fusco		Zach Davis
	President and Chief Executive Officer (Principal Executive Officer)		Senior 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, 2020 and 2019, the related consolidated statements of income, partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020, 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, 2020, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 23, 2021 expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 3 to the consolidated financial statements, the Partnership has changed its method of accounting for leases as of January 1, 2019 due to the adoption of *ASU 2016-02, Leases (Topic 842),* and subsequent amendments thereto.

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 $(21) million, as of December 31, 2020. 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 through the use of internal models, which 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 over the valuation of the level 3 physical liquefaction supply derivatives. This included controls related to the assumptions for significant unobservable inputs. For the level 3 liquefaction supply derivatives selected, we involved valuation professionals with specialized skills who assisted in:

- developing independent fair value estimates and comparing the independently developed estimates to the Partnership’s fair value estimates
- testing the future prices of energy units for unobservable periods and liquidity assumptions by comparing to market data, including quoted or published forward prices for similar commodities.

In addition, we evaluated the Partnership’s assumptions for future prices of energy units for unobservable periods and liquidity by comparing 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 23, 2021

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, 2020, 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, 2020, 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, 2020 and 2019, the related consolidated statements of income, partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes and financial statement schedule I (collectively, the consolidated financial statements), and our report dated February 23, 2021 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 partnership'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 partnership'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 partnership; (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 partnership are being made only in accordance with authorizations of management and directors of the partnership; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the partnership'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 23, 2021

CONSOLIDATED STATEMENTS OF INCOME
(in millions, except per unit data)

	Year Ended December 31,		
	2020	2019	2018
Revenues			
LNG revenues	$ 5,195	$ 5,211	$ 4,827
LNG revenues—affiliate	662	1,312	1,299
Regasification revenues	269	266	261
Other revenues	41	49	39
Total revenues	6,167	6,838	6,426
Operating costs and expenses			
Cost of sales (excluding items shown separately below)	2,505	3,374	3,403
Cost of sales—affiliate	77	7	—
Operating and maintenance expense	629	632	409
Operating and maintenance expense—affiliate	152	138	117
Operating and maintenance expense—related party	13	—	—
Development expense	—	—	2
General and administrative expense	14	11	11
General and administrative expense—affiliate	96	102	73
Depreciation and amortization expense	551	527	424
Impairment expense and loss on disposal of assets	5	7	8
Total operating costs and expenses	4,042	4,798	4,447
Income from operations	2,125	2,040	1,979
Other income (expense)			
Interest expense, net of capitalized interest	(909)	(885)	(733)
Loss on modification or extinguishment of debt	(43)	(13)	(12)
Derivative gain, net	—	—	14
Other income, net	8	31	26
Other income—affiliate	2	2	—
Total other expense	(942)	(865)	(705)
Net income	$ 1,183	$ 1,175	$ 1,274
Basic and diluted net income per common unit	$ 2.32	$ 2.25	$ 2.51
Weighted average number of common units outstanding used for basic and diluted net income per common unit calculation	399.3	348.6	348.6

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, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,210	$ 1,781
Restricted cash	97	181
Accounts and other receivables, net	318	297
Accounts receivable—affiliate	184	105
Advances to affiliate	144	158
Inventory	107	116
Derivative assets	14	17
Other current assets	61	51
Other current assets—affiliate	—	1
Total current assets	2,135	2,707
Property, plant and equipment, net	16,723	16,368
Operating lease assets, net	99	94
Debt issuance costs, net	17	15
Non-current derivative assets	11	32
Other non-current assets, net	160	168
Total assets	$ 19,145	$ 19,384
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accounts payable	$ 12	$ 40
Accrued liabilities	658	709
Accrued liabilities—related party	4	—
Due to affiliates	53	46
Deferred revenue	137	155
Deferred revenue—affiliate	1	1
Current operating lease liabilities	7	6
Derivative liabilities	11	9
Total current liabilities	883	966
Long-term debt, net	17,580	17,579
Non-current operating lease liabilities	90	87
Non-current derivative liabilities	35	16
Other non-current liabilities	1	1
Other non-current liabilities—affiliate	17	20
Commitments and contingencies (see Note 16)		
Partners' equity		
Common unitholders' interest (484.0 million and 348.6 million units issued and outstanding at December 31, 2020 and 2019, respectively)	714	1,792
Subordinated unitholders' interest (zero and 135.4 million units issued and outstanding at December 31, 2020 and 2019, respectively)	—	(996)
General partner's interest (2% interest with 9.9 million units issued and outstanding at December 31, 2020 and 2019)	(175)	(81)
Total partners' equity	539	715
Total liabilities and partners' equity	$ 19,145	$ 19,384

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY
(in millions)

	Common Unitholders' Interest		Subordinated Unitholder's Interest		General Partner's Interest		Total Partners' Equity
	Units	Amount	Units	Amount	Units	Amount	
Balance at December 31, 2017	348.6	$ 1,670	135.4	$ (1,043)	9.9	$ 12	$ 639
Net income	—	899	—	349	—	26	1,274
Distributions							
Common units, $2.19/unit	—	(763)	—	—	—	—	(763)
Subordinated units, $2.19/unit	—	—	—	(296)	—	—	(296)
General partner units	—	—	—	—	—	(54)	(54)
Balance at December 31, 2018	348.6	1,806	135.4	(990)	9.9	(16)	800
Net income	—	829	—	322	—	24	1,175
Distributions							
Common units, $2.42/unit	—	(843)	—	—	—	—	(843)
Subordinated units, $2.42/unit	—	—	—	(328)	—	—	(328)
General partner units	—	—	—	—	—	(89)	(89)
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, $2.565/unit	—	(982)	—	—	—	—	(982)
Subordinated units, $1.915/unit	—	—	—	(259)	—	—	(259)
General partner units	—	—	—	—	—	(118)	(118)
Balance at December 31, 2020	484.0	$ 714	—	$ —	9.9	$ (175)	$ 539

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,		
	2020	2019	2018
Cash flows from operating activities			
Net income	$ 1,183	$ 1,175	$ 1,274
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	551	527	424
Amortization of debt issuance costs, premium and discount	32	34	30
Loss on modification or extinguishment of debt	43	13	12
Total losses (gains) on derivatives, net	49	(72)	87
Net cash provided by (used for) settlement of derivative instruments	(4)	5	32
Impairment expense and loss on disposal of assets	5	7	8
Other	14	11	5
Other—affiliate	(2)	(2)	—
Changes in operating assets and liabilities:			
Accounts and other receivables, net	(21)	16	(122)
Accounts receivable—affiliate	(80)	9	47
Advances to affiliate	8	(41)	(84)
Inventory	8	(16)	(5)
Accounts payable and accrued liabilities	—	(126)	183
Accrued liabilities—related party	4	—	—
Due to affiliates	9	6	(6)
Deferred revenue	(18)	39	3
Other, net	(28)	(36)	(12)
Other, net—affiliate	(2)	(2)	(2)
Net cash provided by operating activities	1,751	1,547	1,874
Cash flows from investing activities			
Property, plant and equipment, net	(972)	(1,331)	(804)
Other	—	(1)	—
Net cash used in investing activities	(972)	(1,332)	(804)
Cash flows from financing activities			
Proceeds from issuances of debt	1,995	2,230	1,100
Repayments of debt	(2,000)	(730)	(1,090)
Debt issuance and other financing costs	(35)	(35)	(8)
Debt extinguishment costs	(39)	(4)	(7)
Distributions to owners	(1,359)	(1,260)	(1,113)
Other	4	5	—
Net cash provided by (used in) financing activities	(1,434)	206	(1,118)
Net increase (decrease) in cash, cash equivalents and restricted cash	(655)	421	(48)
Cash, cash equivalents and restricted cash—beginning of period	1,962	1,541	1,589
Cash, cash equivalents and restricted cash—end of period	$ 1,307	$ 1,962	$ 1,541

Balances per Consolidated Balance Sheets:

	December 31,	
	2020	2019
Cash and cash equivalents	$ 1,210	$ 1,781
Restricted cash	97	181
Total cash, cash equivalents and restricted cash	$ 1,307	$ 1,962

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

NOTE 1—ORGANIZATION AND NATURE OF OPERATIONS

We are a publicly traded Delaware limited partnership formed by Cheniere in 2006. The Sabine Pass LNG terminal is located in Cameron Parish, Louisiana, on the Sabine-Neches Waterway less than four miles from the Gulf Coast. Through our subsidiary, SPL, we are currently operating five natural gas liquefaction Trains and are constructing one additional Train that is expected to be substantially completed in the second half of 2022, for a total production capacity of approximately 30 mtpa of LNG (the "Liquefaction Project") at the Sabine Pass LNG terminal. Through our subsidiary, SPLNG, we own and operate regasification facilities at the Sabine Pass LNG terminal, which includes pre-existing infrastructure of five LNG storage tanks, two marine berths and vaporizers and an additional marine berth that is under construction. We also own a 94-mile pipeline through our subsidiary, CTPL, that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines (the "Creole Trail Pipeline").

As of December 31, 2020, 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. The holders of the units are entitled to participate in partnership distributions and exercise the rights and privileges available to limited partners under our partnership agreement. 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 paid to date have been made from accumulated operating surplus as defined in the partnership agreement.

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.

Although common unitholders are not obligated to fund losses of the Partnership, its 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 after the initial quarterly distributions have been achieved and 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.

As of December 31, 2020, our total securities beneficially owned in the form of common units were held 48.6% by Cheniere, 41.9% by BX CQP Target Holdco L.L.C. ("BX CQP Target Holdco") and other affiliates of The Blackstone Group Inc. ("Blackstone") and Brookfield Asset Management Inc. ("Brookfield") and 7.5% by the public. All of our 2% general partner interest was held by Cheniere. BX CQP Target Holdco's equity interests are 50.01% owned by BIP Chinook Holdco L.L.C., an affiliate of Blackstone and 49.99% owned by BIF IV Cypress Aggregator (Delaware) LLC, an affiliate of Brookfield. The ownership of BX 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 Cheniere Partners and its majority owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation.

Recent Accounting Standards

In March 2020, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("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 optional expedients were available to be used upon issuance of this guidance but we have not yet applied the guidance because we have not yet modified any of our existing contracts for reference rate reform. Once we apply an optional expedient to a modified contract and adopt this standard, the guidance will be applied to all subsequent applicable contract modifications until December 31, 2022, at which time the optional expedients are no longer available.

Use of Estimates

The preparation of 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, revenue recognition, property, plant and equipment, derivative instruments, 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, accounts receivable and accounts payable 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. Non-financial assets and liabilities initially measured at fair value include intangible assets and AROs.

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. Revenues from the sale of LNG are recognized as LNG revenues. LNG regasification capacity payments are recognized as regasification revenues. See Note 13—Revenues from Contracts with Customers for further discussion of revenues.

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

Restricted cash consists 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.

Accounts Receivable

Accounts receivable is 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, 2020 and 2019, we had current expected credit losses on our accounts receivable of $5 million and zero, respectively.

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 and subsequently charged to expense when issued.

Accounting for LNG Activities

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. The costs of lease options are amortized over the life of the lease once obtained. If no land or lease is obtained, the costs are expensed.

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. 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. 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 are recorded in impairment expense and loss (gain) on disposal of assets.

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 impairments related to property, plant and equipment during the years ended December 31, 2020, 2019 and 2018.

Interest Capitalization

We capitalize interest costs during the construction period of our LNG terminal and related assets as construction-in-process. Upon commencement of operations, these costs are transferred out of construction-in-process into terminal and interconnecting pipeline facilities assets and are amortized over the estimated useful life of the asset.

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 primarily classified in our Consolidated Balance Sheets as other assets and other liabilities. We periodically 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 reduce our asset balances to reflect a market basis less than cost and 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 interest rate and 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. When we have the contractual right and intend to net settle, derivative assets and liabilities are reported on a net basis.

Changes in the fair value of our derivative instruments are recorded in earnings, 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, 2020, 2019 and 2018. See Note 8—Derivative Instruments for additional details about our derivative instruments.

Leases

We adopted ASU 2016-02, *Leases (Topic 842)*, and subsequent amendments thereto ("ASC 842") on January 1, 2019 using the optional transition approach to apply the standard at the beginning of the first quarter of 2019 with no retrospective adjustments to prior periods. The adoption of the standard resulted in the recognition of right-of-use assets and lease liabilities for operating leases of approximately $100 million on our Consolidated Balance Sheets, with no material impact on our Consolidated Statements of Income or Consolidated Statements of Cash Flows.

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. We did not have any financing leases as of December 31, 2020. Operating 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 lease right-of-use assets and liabilities are generally recognized based on the present value of lease payments over the lease term. In determining the present value of 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. Operating leases are included in operating lease assets, net, current operating lease liabilities and non-current operating lease liabilities on our Consolidated Balance Sheets. 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 cash and cash equivalents, restricted cash, derivative instruments and accounts receivable. We maintain cash balances at financial institutions, which may at times be in excess of federally insured levels. We have not incurred losses related to these balances to date.

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 other current assets. Our interest rate derivative instruments are placed with investment grade financial institutions whom we believe are acceptable credit risks. We monitor counterparty creditworthiness on an ongoing basis; however, we cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, we may not realize the benefit of some of our derivative instruments.

SPL has entered into fixed price long-term SPAs generally with terms of20 years with eight 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.

SPLNG has entered intotwo long-term TUAs with third parties for regasification capacity at the Sabine Pass LNG terminal. SPLNG is dependent on the respective customers' creditworthiness and their willingness to perform under their respective TUAs. SPLNG has mitigated this credit risk by securing TUAs for a significant portion of its regasification capacity with creditworthy third-party customers with a minimum Standard & Poor's rating of A.

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 and printing costs. If debt issuance costs are incurred in connection with a line of credit arrangement or on undrawn funds, they 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 gain (loss) on modification or extinguishment of debt on our Consolidated Statements of Income.

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, 2020, the tax basis of our assets and liabilities was $8.2 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.

On September 14, 2020, U.S. Department of the Treasury ("Treasury") and the Internal Revenue Service ("IRS") issued final and proposed regulations ("Regulations") that modified the deductibility of interest expense in certain circumstances under the Tax Cuts and Jobs Act ("TCJA"). Cheniere Partners has elected to conform with the Regulations which allow the partnership to deduct additional interest expense for tax years ended December 31, 2019 and 2018. As required under the Bipartisan Budget Act of 2015, Cheniere Partners adopted the Regulations by filing an Administrative Adjustment Request ("AAR") and Forms 8985, *Pass-Through Statement—Transmittal/Partnership Adjustment Tracking Report,* and 8986, *Partner's share of Adjustment(s) to Partnership Related Item(s),* for the tax years ended December 31, 2019 and 2018. Cheniere Partners also furnished Form 8986 to each of its partners at the same time the AAR was filed with the IRS. Unitholders are urged to consult their tax advisor regarding steps needed to account for these changes.

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 Cheniere Partners in total when evaluating financial performance and for purposes of allocating resources.

NOTE 4—RESTRICTED CASH

Restricted cash consists 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. As of December 31, 2020 and 2019, we had $97 million and $181 million of current restricted cash, respectively.

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.

NOTE 5—ACCOUNTS AND OTHER RECEIVABLES

As of December 31, 2020 and 2019, accounts and other receivables, net consisted of the following (in millions):

	December 31,	
	2020	2019
SPL trade receivable	$ 300	$ 283
Other accounts receivable	18	14
Total accounts and other receivables, net	$ 318	$ 297

NOTE 6—INVENTORY

As of December 31, 2020 and 2019, inventory consisted of the following (in millions):

	December 31,	
	2020	2019
Natural gas	$ 17	$ 9
LNG	8	27
Materials and other	82	80
Total inventory	$ 107	$ 116

NOTE 7—PROPERTY, PLANT AND EQUIPMENT

As of December 31, 2020 and 2019, property, plant and equipment, net consisted of the following (in millions):

	December 31,	
	2020	2019
LNG terminal costs		
LNG terminal and interconnecting pipeline facilities	$ 16,908	$ 16,894
LNG terminal construction-in-process	2,154	1,275
Accumulated depreciation	(2,344)	(1,807)
Total LNG terminal costs, net	16,718	16,362
Fixed assets		
Fixed assets	29	27
Accumulated depreciation	(24)	(21)
Total fixed assets, net	5	6
Property, plant and equipment, net	$ 16,723	$ 16,368

The following table shows depreciation expense and offsets to LNG terminal costs during the years ended December 31, 2020, 2019 and 2018 (in millions):

	Year Ended December 31,		
	2020	2019	2018
Depreciation expense	$ 547	$ 523	$ 413
Offsets to LNG terminal costs (1)	—	48	94

(1) We realize 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 7 and 50 years, as follows:

Components	Useful life (yrs)
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	7-50
Other	10-30

Fixed Assets and Other

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

NOTE 8—DERIVATIVE INSTRUMENTS

We have entered into commodity derivatives consisting of natural gas supply contracts for the commissioning and operation of the Liquefaction Project ("Physical Liquefaction Supply Derivatives") and associated economic hedges (collectively, the "Liquefaction Supply Derivatives").

We recognize our derivative instruments as either assets or liabilities and measure those instruments at fair value. None of 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.

The following table shows the fair value of our derivative instruments that are required to be measured at fair value on a recurring basis as of December 31, 2020 and 2019, which are classified as derivative assets, non-current derivative assets, derivative liabilities or non-current derivative liabilities in our Consolidated Balance Sheets (in millions).

	Fair Value Measurements as of							
	December 31, 2020				December 31, 2019			
	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)	$ 1	$ (1)	$ (21)	$ (21)	$ 3	$ (3)	$ 24	$ 24

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

The fair value of our Physical 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 evaluating whether the respective market is available as pipeline infrastructure is developed. The fair value of our Physical Liquefaction Supply Derivatives incorporates risk premiums related to the satisfaction of conditions precedent, such as completion and placement into service of relevant pipeline infrastructure to accommodate marketable physical gas flow. As of December 31, 2020 and 2019, some of our Physical Liquefaction Supply Derivatives existed within markets for which the pipeline infrastructure was under development to accommodate marketable physical gas flow.

We include a portion of our Physical 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, volatility and contract duration.

The Level 3 fair value measurements of natural gas positions within our Physical Liquefaction Supply Derivatives could be materially impacted by a significant change in certain natural gas prices. The following table includes quantitative information for the unobservable inputs for our Level 3 Physical Liquefaction Supply Derivatives as of December 31, 2020:

	Net Fair Value Liability (in millions)	Valuation Approach	Significant Unobservable Input	Range of Significant Unobservable Inputs / Weighted Average (1)
Physical Liquefaction Supply Derivatives	$(21)	Market approach incorporating present value techniques	Henry Hub basis spread	$(0.350) - $0.092 / $(0.005)

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

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

The following table shows the changes in the fair value of our Level 3 Physical Liquefaction Supply Derivatives during the years ended December 31, 2020, 2019 and 2018 (in millions):

	Year Ended December 31,		
	2020	2019	2018
Balance, beginning of period	$ 24	$ (25)	$ 43
Realized and mark-to-market gains (losses):			
Included in cost of sales	(43)	6	(3)
Purchases and settlements:			
Purchases	5	—	(37)
Settlements	(7)	42	(29)
Transfers into Level 3, net (1)	—	1	1
Balance, end of period	$ (21)	$ 24	$ (25)
Change in unrealized gain (loss) relating to instruments still held at end of period	$ (43)	$ 6	$ (3)

(1) Transferred into Level 3 as a result of unobservable market, or out of Level 3 as a result of observable market for the underlying natural gas purchase agreements.

Derivative assets and liabilities arising from our derivative contracts with the same counterparty are reported on a net basis, as all counterparty derivative contracts provide for the unconditional right of set-off in the event of default. 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. 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.

Interest Rate Derivatives

We previously had interest rate swaps ("CQP Interest Rate Derivatives") to hedge a portion of the variable interest payments on our credit facilities. In October 2018, we terminated the CQP Interest Rate Derivatives related to the 2016 CQP Credit Facilities.

The following table shows the changes in the fair value and settlements of our Interest Rate Derivatives recorded in derivative gain (loss), net on our Consolidated Statements of Income during the years ended December 31, 2020, 2019 and 2018 (in millions):

	Year Ended December 31,		
	2020	2019	2018
CQP Interest Rate Derivatives gain	$ —	$ —	$ 14

Liquefaction Supply Derivatives

SPL has entered into primarily index-based physical natural gas supply contracts and associated economic hedges to purchase natural gas for the commissioning and operation of the Liquefaction Project. The remaining terms of the physical natural gas supply contracts range up to 10 years, some of which commence upon the satisfaction of certain events or states of affairs.

The notional natural gas position of our Liquefaction Supply Derivatives was approximately4,970 TBtu and 3,663 TBtu as of December 31, 2020 and 2019, respectively, of which 91 TBtu and zero TBtu, respectively, were for a natural gas supply contract that SPL has with a related party.

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, 2020	December 31, 2019
Derivative assets	$ 14	$ 17
Non-current derivative assets	11	32
Total derivative assets	25	49
Derivative liabilities	(11)	(9)
Non-current derivative liabilities	(35)	(16)
Total derivative liabilities	(46)	(25)
Derivative asset (liability), net	$ (21)	$ 24

(1) Does not include collateral posted with counterparties by us of $4 million and $2 million for such contracts, which are included in other current assets in our Consolidated Balance Sheets as of December 31, 2020 and 2019, respectively. Includes a natural gas supply contract that SPL has with a related party, which had a fair value of zero as of December 31, 2020.

The following table shows the changes in the fair value, settlements and location of our Liquefaction Supply Derivatives recorded on our Consolidated Statements of Income during the years ended December 31, 2020, 2019 and 2018 (in millions):

		Year Ended December 31,		
	Consolidated Statements of Income Location (1)	2020	2019	2018
Liquefaction Supply Derivatives gain (loss)	LNG revenues	$ —	$ 1	$ (1)
Liquefaction Supply Derivatives gain (loss)	Cost of sales	(49)	71	(100)

(1) Does not include the realized 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.

Consolidated Balance Sheets Presentation

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

	Liquefaction Supply Derivatives
As of December 31, 2020	
Gross assets	$ 69
Offsetting amounts	(44)
Net assets	$ 25
Gross liabilities	$ (48)
Offsetting amounts	2
Net liabilities	$ (46)
As of December 31, 2019	
Gross assets	$ 51
Offsetting amounts	(2)
Net assets	$ 49
Gross liabilities	$ (27)
Offsetting amounts	2
Net liabilities	$ (25)

NOTE 9—OTHER NON-CURRENT ASSETS

As of December 31, 2020 and 2019, other non-current assets, net consisted of the following (in millions):

	December 31,	
	2020	2019
Advances made to municipalities for water system enhancements	$ 84	$ 87
Advances and other asset conveyances to third parties to support LNG terminal	33	35
Tax-related prepayments and receivables	17	17
Information technology service prepayments	6	6
Advances made under EPC and non-EPC contracts	9	15
Other	11	8
Total other non-current assets, net	$ 160	$ 168

NOTE 10—ACCRUED LIABILITIES

As of December 31, 2020 and 2019, accrued liabilities consisted of the following (in millions):

	December 31,	
	2020	2019
Interest costs and related debt fees	$ 203	$ 241
Accrued natural gas purchases	374	325
LNG terminal and related pipeline costs	71	135
Other accrued liabilities	10	8
Total accrued liabilities	$ 658	$ 709

NOTE 11—DEBT

As of December 31, 2020 and 2019, our debt consisted of the following (in millions):

	December 31,	
	2020	2019
Long-term debt:		
SPL — 4.200% to 6.25% senior secured notes due between 2022 and 2037 and working capital facility ("2020 SPL Working Capital Facility")	$ 13,650	$ 13,650
Cheniere Partners — 4.500% to 5.625% senior notes due between 2025 and 2029 and credit facilities ("2019 CQP Credit Facilities")	4,100	4,100
Unamortized premium, discount and debt issuance costs, net	(170)	(171)
Total long-term debt, net	17,580	17,579
Current debt:		
SPL — $1.2 billion Amended and Restated SPL Working Capital Facility ("2015 SPL Working Capital Facility")	—	—
Total debt, net	$ 17,580	$ 17,579

Below is a schedule of future principal payments that we are obligated to make, based on current construction schedules, on our outstanding debt at December 31, 2020 (in millions):

Years Ending December 31,	Principal Payments
2021	$ —
2022	1,000
2023	1,500
2024	2,000
2025	3,523
Thereafter	9,727
Total	$ 17,750

Issuances and Redemptions

The following table shows the issuances and redemptions of long-term debt during the year ended December 31, 2020 (in millions):

Issuances	**Principal Amount Issued**
SPL — 4.500% Senior Secured Notes due 2030 (the "2030 SPL Senior Notes") (1)	$ 2,000
Year Ended December 31, 2020 total	$ 2,000

Redemptions	**Amount Redeemed**
SPL — 5.625% Senior Secured Notes due 2021 (the "2021 SPL Senior Notes") (1)	$ (2,000)
Year Ended December 31, 2020 total	$ (2,000)

(1) Proceeds of the 2030 SPL Senior Notes, along with available cash, were used to redeem all of SPL's outstanding 2021 SPL Senior Notes, resulting in the recognition of debt extinguishment costs of $43 million for the year ended December 31, 2020 relating to the payment of early redemption fees and write off of unamortized debt premium and issuance costs.

Credit Facilities

Below is a summary of our credit facilities outstanding as of December 31, 2020 (in millions):

	2020 SPL Working Capital Facility (1)	**2019 CQP Credit Facilities**
Original facility size	$ 1,200	$ 1,500
Less:		
Outstanding balance	—	—
Commitments prepaid or terminated	—	750
Letters of credit issued	413	—
Available commitment	$ 787	$ 750
Priority ranking	Senior secured	Senior secured
Interest rate on available balance	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%
Weighted average interest rate of outstanding balance	n/a	n/a
Maturity date	March 19, 2025	May 29, 2024

(1) The 2020 SPL Working Capital Facility contains customary conditions precedent for extensions of credit, as well as customary affirmative and negative covenants. SPL pays a commitment fee equal to an annual rate of 0.1% to 0.3% (depending on the then-current rating of SPL), which accrues on the daily amount of the total commitment less the sum of (1) the outstanding principal amount of loans, (2) letters of credit issued and (3) the outstanding principal amount of swing line loans.

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.

As of December 31, 2020, 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,		
	2020	2019	2018
Total interest cost	$ 1,005	$ 972	$ 936
Capitalized interest	(96)	(87)	(203)
Total interest expense, net of capitalized interest	$ 909	$ 885	$ 733

Fair Value Disclosures

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

	December 31, 2020		December 31, 2019	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Senior notes — Level 2 (1)	$ 16,950	$ 19,113	$ 16,950	$ 18,320
Senior notes — Level 3 (2)	800	1,036	800	934
Credit facilities (3)	—	—	—	—

(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.

(3) The Level 3 estimated fair value approximates the principal amount 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 which are classified as operating leases.

Our policy is to recognize leases on our balance sheet 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. As our leases generally do not provide an implicit rate, in order to calculate the lease liability, we discounted our expected future lease payments using our relevant subsidiary's incremental borrowing rate at the later of January 1, 2019 or the commencement date of the lease. The incremental borrowing rate is an estimate of the rate of interest that a given subsidiary would have to pay to borrow on a collateralized basis over a similar term to that of the lease term.

Many of our leases contain renewal options exercisable at our sole discretion.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, such as when necessary to satisfy obligations that existed at the execution of the lease or when the non-renewal would otherwise result in a significant economic penalty.

We have elected the practical expedient to omit leases with an initial term of 12 months or less ("short-term lease") from recognition on the balance sheet.We recognize short-term lease payments on a straight-line basis over the lease term and variable payments under short-term leases in the period in which the obligation is incurred.

Certain of our leases contain non-lease components which are not separated from the lease components when calculating the right-of-use asset and lease liability per our use of the practical expedient to combine both components of an arrangement for all classes of leased assets.

Certain of our leases also contain variable payments, such as inflation, that are not included when calculating the right-of-use asset and lease liability unless the payments are in-substance fixed. We recognize lease expense for operating leases on a straight-line basis over the lease term.

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	2020	2019
Right-of-use assets—Operating	Operating lease assets, net	$ 99	$ 94
Current operating lease liabilities	Current operating lease liabilities	7	6
Non-current operating lease liabilities	Non-current operating lease liabilities	90	87

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

		Year Ended December 31,	
	Consolidated Statements of Income Location	2020	2019
Operating lease cost (1)	Operating costs and expenses (2)	$ 12	$ 11

(1) Includes $1 million and $1 million of variable lease costs paid to the lessor during the years ended December 31, 2020 and 2019, 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.

During the year ended December 31, 2018, we recognized rental expense for all operating leases of $16 million.

Future annual minimum lease payments for operating leases as of December 31, 2020 are as follows (in millions):

Years Ending December 31,	Operating Leases
2021	$ 11
2022	11
2023	11
2024	11
2025	11
Thereafter	116
Total lease payments	171
Less: Interest	(74)
Present value of lease liabilities	$ 97

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

	December 31,	
	2020	2019
Weighted-average remaining lease term (in years)	24.5	26.4
Weighted-average discount rate	4.1 %	4.8%

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

	Year Ended December 31,	
	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 11	$ 10

NOTE 13—REVENUES FROM CONTRACTS WITH CUSTOMERS

The following table represents a disaggregation of revenue earned from contracts with customers during the years ended December 31, 2020, 2019 and 2018 (in millions):

	Year Ended December 31,		
	2020	2019	2018
LNG revenues (1)	$ 5,195	$ 5,210	$ 4,828
LNG revenues—affiliate	662	1,312	1,299
Regasification revenues	269	266	261
Other revenues	41	49	39
Total revenues from customers	6,167	6,837	6,427
Net derivative gain (loss) (2)	—	1	(1)
Total revenues	$ 6,167	$ 6,838	$ 6,426

(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. 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 equal to approximately 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.

Regasification Revenues

The Sabine Pass LNG terminal has operational regasification capacity of approximately4 Bcf/d. Approximately 2 Bcf/d of the regasification capacity at the Sabine Pass LNG terminal has been reserved under two long-term TUAs with unaffiliated third-party customers, under which they are required to pay fixed monthly fees regardless of their use of the LNG terminal. Each of the customers has reserved approximately 1 Bcf/d of regasification capacity. The customers are each obligated to make monthly capacity payments to SPLNG 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. The remaining 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 Total Gas & Power North America, Inc. ("Total"), whereby upon substantial completion of Train 5 of the Liquefaction Project, SPL gained access to substantially all of Total's capacity and other services provided under Total's 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, permit SPL to more flexibly manage its LNG storage capacity and accommodate the development of Train 6. Notwithstanding any arrangements between Total and SPL, payments required to be made by Total to SPLNG will continue to be made by Total to SPLNG in accordance with its TUA and we continue to recognize the payments received from Total as revenue. During the years ended December 31, 2020, 2019 and 2018, SPL recorded $129 million, $104 million and $30 million, respectively, as operating and maintenance expense under this partial TUA assignment agreement.

Deferred Revenue Reconciliation

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, 2020
Deferred revenues, beginning of period	$ 155
Cash received but not yet recognized	137
Revenue recognized from prior period deferral	(155)
Deferred revenues, end of period	$ 137

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, 2020 and 2019 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 as of December 31, 2020 and 2019:

	December 31, 2020		December 31, 2019	
	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)
LNG revenues	$ 52.1	9	$ 55.0	10
LNG revenues—affiliate	0.1	1	—	0
Regasification revenues	2.1	5	2.4	5
Total revenues	$ 54.3		$ 57.4	

(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 42% and 52% of our LNG revenues from contracts included in the table above during the years ended December 31, 2020 and 2019, respectively, were related to variable consideration received from customers. During each of the years ended December 31, 2020 and 2019, approximately 3% 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 for the years ended December 31, 2020, 2019 and 2018 (in millions):

	Year Ended December 31,		
	2020	2019	2018
LNG revenues—affiliate			
Cheniere Marketing Agreements	$ 632	$ 1,309	$ 1,299
Contracts for Sale and Purchase of Natural Gas and LNG	30	3	—
Total LNG revenues—affiliate	662	1,312	1,299
Cost of sales—affiliate			
Cheniere Marketing Agreements	61	—	—
Contracts for Sale and Purchase of Natural Gas and LNG	16	7	—
Total Cost of sales—affiliate	77	7	—
Operating and maintenance expense—affiliate			
Services Agreements	152	138	117
Operating and maintenance expense—related party			
Natural Gas Transportation and Storage Agreements	13	—	—
General and administrative expense—affiliate			
Services Agreements	96	102	73
Other income—affiliate			
Cooperative Endeavor Agreement	2	2	—

As of December 31, 2020 and 2019, we had $184 million and $105 million, respectively, of accounts receivable—affiliate, under the agreements described below.

Cheniere Marketing Agreements

Cheniere Marketing SPA

Cheniere Marketing has an SPA ("Base SPA") with SPL to purchase, at Cheniere Marketing's option, any LNG produced by SPL in excess of that required for other customers at a price of 115% of Henry Hub plus $3.00 per MMBtu of LNG.

In May 2019, SPL and Cheniere Marketing entered into an amendment to the Base SPA to remove certain conditions related to the sale of LNG from Trains 5 and 6 of the Liquefaction Project and provide that cargoes rejected by Cheniere Marketing under the Base SPA can be sold by SPL to Cheniere Marketing at a contract price equal to a portion of the estimated net profits from the sale of such cargo.

Cheniere Marketing Master SPA

SPL has an agreement with Cheniere Marketing that allows the parties to sell and purchase LNG with each other by executing and delivering confirmations under this agreement. SPL executed a confirmation with Cheniere Marketing that obligated Cheniere Marketing in certain circumstances to buy LNG cargoes produced during the period while Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") had control of, and was commissioning, Train 5 of the Liquefaction Project.

Cheniere Marketing Letter Agreements

In December 2020, SPL and Cheniere Marketing entered into a letter agreement for the sale of up to 30 cargoes scheduled for delivery in 2021 at a price of 115% of Henry Hub plus $0.728 per MMBtu.

In December 2019, SPL and Cheniere Marketing entered into a letter agreement for the sale of up to 43 cargoes that were delivered in 2020 at a price of 115% of Henry Hub plus $1.67 per MMBtu.

In May 2019, SPL and Cheniere Marketing entered into a letter agreement for the sale of up to 20 cargoes totaling approximately 70 million MMBtu that were delivered between May 3 and December 31, 2019 at a price of 115% of Henry Hub plus $2.00 per MMBtu.

Facility Swap Agreement

In August 2020, SPL 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 operational 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.

Natural Gas Transportation and Storage Agreements

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, with initial primary terms of up to 10 years with extension rights. We recorded operating and maintenance expense—related party of $13 million in the year ended December 31, 2020 and accrued liabilities—related party of $4 million as of December 31, 2020 with this related party.

Services Agreements

As of December 31, 2020 and 2019, we had $144 million and $158 million of advances to affiliates, respectively, under the services agreements described below. The non-reimbursement amounts incurred under these agreements are recorded in general and administrative expense—affiliate.

Cheniere Partners Services Agreement

We have a services agreement with Cheniere Terminals, a subsidiary of Cheniere, pursuant to which Cheniere Terminals is entitled to a quarterly non-accountable overhead reimbursement charge of $3 million (adjusted for inflation) for the provision of various general and administrative services for our benefit. In addition, Cheniere Terminals is entitled to reimbursement for all audit, tax, legal and finance fees incurred by Cheniere Terminals that are necessary to perform the services under the agreement.

Cheniere Investments Information Technology Services Agreement

Cheniere Investments has an information technology services agreement with Cheniere, pursuant to which Cheniere Investments' subsidiaries receive certain information technology services. On a quarterly basis, the various entities receiving the benefit are invoiced by Cheniere Investments according to the cost allocation percentages set forth in the agreement. In addition, Cheniere is entitled to reimbursement for all costs incurred by Cheniere that are necessary to perform the services under the agreement.

SPLNG O&M Agreement

SPLNG has a long-term operation and maintenance agreement (the "SPLNG O&M Agreement") with Cheniere Investments pursuant to which SPLNG receives all necessary services required to operate and maintain the Sabine Pass LNG receiving terminal. SPLNG pays a fixed monthly fee of $130,000 (indexed for inflation) under the SPLNG O&M Agreement and the cost of a bonus equal to 50% of the salary component of labor costs in certain circumstances to be agreed upon between SPLNG and Cheniere Investments at the beginning of each operating year. In addition, SPLNG is required to reimburse Cheniere Investments for its operating expenses, which consist primarily of labor expenses. Cheniere Investments provides the services required under the SPLNG O&M Agreement pursuant to a secondment agreement with a wholly owned subsidiary of Cheniere. All payments received by Cheniere Investments under the SPLNG O&M Agreement are required to be remitted to such subsidiary.

SPLNG MSA

SPLNG has a long-term management services agreement (the "SPLNG MSA") with Cheniere Terminals, pursuant to which Cheniere Terminals manages the operation of the Sabine Pass LNG receiving terminal, excluding those matters provided for under the SPLNG O&M Agreement. SPLNG pays a monthly fixed fee of $520,000 (indexed for inflation) under the SPLNG MSA.

SPL O&M Agreement

SPL has an operation and maintenance agreement (the "SPL O&M Agreement") with Cheniere Investments pursuant to which SPL receives all of the necessary services required to construct, operate and maintain the Liquefaction Project. Before each Train of the Liquefaction Project is operational, the services to be provided include, among other services, obtaining governmental approvals on behalf of SPL, preparing an operating plan for certain periods, obtaining insurance, preparing staffing plans and preparing status reports. After each Train is operational, the services include all necessary services required to operate and maintain the Train. Prior to the substantial completion of each Train of the Liquefaction Project, in addition to reimbursement of operating expenses, SPL is required to pay a monthly fee equal to 0.6% of the capital expenditures incurred in the previous month. After substantial completion of each Train, for services performed while the Train is operational, SPL will pay, in addition to the reimbursement of operating expenses, a fixed monthly fee of $83,333 (indexed for inflation) for services with respect to the Train. Cheniere Investments provides the services required under the SPL O&M Agreement pursuant to a secondment agreement with a wholly owned subsidiary of Cheniere. All payments received by Cheniere Investments under the SPL O&M Agreement are required to be remitted to such subsidiary.

SPL MSA

SPL has a management services agreement (the "SPL MSA") with Cheniere Terminals pursuant to which Cheniere Terminals manages the construction and operation of the Liquefaction Project, excluding those matters provided for under the SPL O&M Agreement. The services include, among other services, exercising the day-to-day management of SPL's affairs and business, managing SPL's regulatory matters, managing bank and brokerage accounts and financial books and records of SPL's business and operations, entering into financial derivatives on SPL's behalf and providing contract administration services for all contracts associated with the Liquefaction Project. Prior to the substantial completion of each Train of the Liquefaction Project, SPL pays a monthly fee equal to 2.4% of the capital expenditures incurred in the previous month. After substantial completion of each Train, SPL will pay a fixed monthly fee of $541,667 (indexed for inflation) for services with respect to such Train.

CTPL O&M Agreement

CTPL has an amended long-term operation and maintenance agreement (the "CTPL O&M Agreement") with Cheniere Investments pursuant to which CTPL receives all necessary services required to operate and maintain the Creole Trail Pipeline. CTPL is required to reimburse Cheniere Investments for its operating expenses, which consist primarily of labor expenses. Cheniere Investments provides the services required under the CTPL O&M Agreement pursuant to a secondment agreement with a wholly owned subsidiary of Cheniere. All payments received by Cheniere Investments under the CTPL O&M Agreement are required to be remitted to such subsidiary.

Natural Gas Supply Agreement

SPL is party to a natural gas supply agreement with a related party in the ordinary course of business, to obtain feed gas for the operation of the Liquefaction Project. The term of the agreement is for five years, which can commence no earlier than November 1, 2021 and no later than November 1, 2022, following the achievement of contractually-defined conditions precedent.

Agreement to Fund SPLNG's Cooperative Endeavor Agreements

SPLNG has executed Cooperative Endeavor Agreements ("CEAs") with various Cameron Parish, Louisiana taxing authorities that allowed them to collect certain annual property tax payments 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 may 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. 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 ad valorem tax levied on our LNG terminal in the year the Cameron Parish dollar-for-dollar credit is applied.

On a consolidated basis, these advance tax payments were recorded to other non-current assets, and payments from Cheniere Marketing that SPLNG utilized to make the ad valorem tax payments were recorded as obligations. We had $2 million and $2 million in due to affiliates and $17 million and $20 million of other non-current liabilities—affiliate resulting from these payments received from Cheniere Marketing as of December 31, 2020 and 2019, respectively.

Contracts for Sale and Purchase of Natural Gas and LNG

SPLNG is able to sell and purchase natural gas and LNG under agreements with Cheniere Marketing. Under these agreements, SPLNG purchases natural gas or LNG from Cheniere Marketing at a sales price equal to the actual purchase price paid by Cheniere Marketing to suppliers of the natural gas or LNG, plus any third-party costs incurred by Cheniere Marketing with respect to the receipt, purchase and delivery of natural gas or LNG to the Sabine Pass LNG terminal.

SPL has an agreement with CCL that allows them to sell and purchase natural gas from each other. Natural gas purchased under this agreement 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. Natural gas sold under this agreement is recorded as LNG revenues—affiliate.

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. Accordingly, Tug Services distributed $6 million, $8 million and $6 million during the years ended December 31, 2020, 2019 and 2018, 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.

LNG Terminal Export Agreement

SPLNG and Cheniere Marketing have an LNG terminal export agreement that provides Cheniere Marketing the ability to export LNG from the Sabine Pass LNG terminal. SPLNG did not record any revenues associated with this agreement during the years ended December 31, 2020, 2019 and 2018.

State Tax Sharing Agreements

SPLNG has a state tax sharing agreement with Cheniere. Under this agreement, Cheniere has agreed to prepare and file all state and local tax returns which SPLNG 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, SPLNG will pay to Cheniere an amount equal to the state and local tax that SPLNG would be required to pay if its state and local tax liability were calculated on a separate company basis. There have been no state and local taxes paid by Cheniere for which Cheniere could have demanded payment from SPLNG under this agreement; therefore, Cheniere has not demanded any such payments from SPLNG. The agreement is effective for tax returns due on or after January 1, 2008.

SPL has a state tax sharing agreement with Cheniere. Under this agreement, Cheniere has agreed to prepare and file all state and local tax returns which SPL 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, SPL will pay to Cheniere an amount equal to the state and local tax that SPL would be required to pay if SPL's state and local tax liability were calculated on a separate company basis. There have been no state and local taxes paid by Cheniere for which Cheniere could have demanded payment from SPL under this agreement; therefore, Cheniere has not demanded any such payments from SPL. The agreement is effective for tax returns due on or after August 2012.

CTPL has a state tax sharing agreement with Cheniere. Under this agreement, Cheniere has agreed to prepare and file all state and local tax returns which CTPL 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, CTPL will pay to Cheniere an amount equal to the state and local tax that CTPL would be required to pay if CTPL's state and local tax liability were calculated on a separate company basis. There have been no state and local taxes paid by Cheniere for which Cheniere could have demanded payment from CTPL under this agreement; therefore, Cheniere has not demanded any such payments from CTPL. The agreement is effective for tax returns due on or after May 2013.

NOTE 15—NET INCOME PER COMMON UNIT

Net income per common unit for a given period is based on the distributions that will be made to the unitholders with respect to the period plus an allocation of undistributed net income based on provisions of the partnership agreement, divided by the weighted average number of common units outstanding. Distributions paid by us are presented on the Consolidated Statements of Partners' Equity. On January 27, 2021, we declared a $0.655 distribution per common unit and the related distribution to our general partner and IDR holders that was paid on February 12, 2021 to unitholders of record as of February 8, 2021 for the period from October 1, 2020 to December 31, 2020.

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 to 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 Units: Common Units	Limited Partner Units: Subordinated Units	General Partner Units	IDR
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		$ 2.32	$ 1.67		
Year Ended December 31, 2019					
Net income	$ 1,175				
Declared distributions	1,278	858	333	26	62
Assumed allocation of undistributed net loss (1)	$ (103)	(73)	(28)	(2)	—
Assumed allocation of net income		$ 785	$ 305	$ 24	$ 62
Weighted average units outstanding		348.6	135.4		
Basic and diluted net income per unit		$ 2.25	$ 2.25		
Year Ended December 31, 2018					
Net income	$ 1,274				
Declared distributions	1,162	795	309	22	36
Assumed allocation of undistributed net income (1)	$ 112	79	31	2	—
Assumed allocation of net income		$ 874	$ 340	$ 24	$ 36
Weighted average units outstanding		348.6	135.4		
Basic and diluted net income per unit		$ 2.51	$ 2.51		

(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.

NOTE 16—COMMITMENTS AND CONTINGENCIES

We have various contractual obligations which are recorded as liabilities in our Consolidated Financial Statements. Other items, such as certain purchase commitments and other executed contracts which do not meet the definition of a liability as of December 31, 2020, are not recognized as liabilities but require disclosures in our Consolidated Financial Statements.

LNG Terminal Commitments and Contingencies

Obligations under EPC Contract

SPL has a lump sum turnkey contract with Bechtel for the engineering, procurement and construction of Train 6 of the Liquefaction Project. The EPC contract price for Train 6 of the Liquefaction Project is approximately $2.5 billion, reflecting amounts incurred under change orders through December 31, 2020, and including estimated costs for the third marine berth that is currently under construction. As of December 31, 2020, we have incurred $1.9 billion under this contract. SPL has the right to terminate the EPC contract for its convenience, in which case Bechtel will be paid (1) the portion of the contract price for the work performed, (2) costs reasonably incurred by Bechtel on account of such termination and demobilization and (3) a lump sum of up to $30 million depending on the termination date.

Obligations under SPAs

SPL has third-party SPAs which obligate SPL to purchase and liquefy sufficient quantities of natural gas to deliver contracted volumes of LNG to the customers' vessels, subject to completion of construction of specified Trains of the Liquefaction Project.

Obligations under LNG TUAs

SPLNG has third-party TUAs with Total and Chevron U.S.A. Inc. to provide berthing for LNG vessels and for the unloading, storage and regasification of LNG at the Sabine Pass LNG terminal.

Obligations under Natural Gas Supply, Transportation and Storage Service Agreements

SPL has physical natural gas supply contracts to secure natural gas feedstock for the Liquefaction Project. The remaining terms of these contracts range up to 10 years, some of which commence upon the satisfaction of certain events or states of affairs. As of December 31, 2020, SPL has secured up to approximately 4,950 TBtu of natural gas feedstock through natural gas supply contracts, a portion of which are considered purchase obligations if the certain events or states of affairs are satisfied.

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, 2020, SPL's obligations under natural gas supply, transportation and storage service agreements for contracts in which conditions precedent were met were as follows (in millions):

Years Ending December 31,	Payments Due (1)
2021	$ 2,949
2022	1,785
2023	1,294
2024	884
2025	767
Thereafter	2,210
Total	$ 9,889

(1) Pricing of natural gas supply contracts are variable based on market commodity basis prices adjusted for basis spread Amounts included are based on estimated forward prices and basis spreads as of December 31, 2020. 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.

Services Agreements

We have certain services agreements with affiliates. See Note 14—Related Party Transactions for information regarding such agreements.

Restricted Net Assets

At December 31, 2020, our restricted net assets of consolidated subsidiaries were approximately $982 million.

Other Commitments

State Tax Sharing Agreements

SPLNG, SPL and CTPL have state tax sharing agreements with Cheniere. See Note 14—Related Party Transactions for information regarding such agreements.

Other Agreements

In the ordinary course of business, we have entered into certain multi-year licensing and service agreements, none of which are considered material to our financial position.

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. In the opinion of management, as of December 31, 2020, 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 customers with revenues of 10% or greater of total revenues from external customers and customers with accounts receivable, net balances of 10% or greater of total accounts receivable, net from external customers:

	Percentage of Total Revenues from External Customers			Percentage of Accounts Receivable, Net from External Customers	
	Year Ended December 31,			December 31,	
	2020	2019	2018	2020	2019
Customer A	24%	27%	28%	31%	21%
Customer B	15%	18%	21%	21%	13%
Customer C	17%	19%	23%	*	22%
Customer D	18%	20%	19%	22%	13%
Customer E	*	*	—%	*	13%
Customer F	11%	*	*	*	14%

* 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,		
	2020	2019	2018
United States	$ 2,769	$ 2,354	$ 1,880
India	970	1,113	981
South Korea	924	1,071	1,168
Ireland	842	988	1,098
Total	$ 5,505	$ 5,526	$ 5,127

NOTE 18—SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2020	2019	2018
Cash paid during the period for interest, net of amounts capitalized	$ 904	$ 829	$ 719

The balance in property, plant and equipment, net funded with accounts payable and accrued liabilities (including affiliate) was $212 million, $291 million and $263 million as of December 31, 2020, 2019 and 2018, respectively.

NOTE 19—SUBSEQUENT EVENTS

In February 2021, SPL entered into a note purchase agreement for the sale of approximately $147 million aggregate principal amount of 2.95% Senior Secured Notes due 2037 (the "2.95% SPL 2037 Senior Secured Notes") on a private placement basis. The 2.95% SPL 2037 Senior Secured Notes are expected to be issued in December 2021, and the net proceeds are expected to be used to refinance a portion of SPL's outstanding Senior Secured Notes due 2022. The 2.95% SPL 2037 Senior Secured Notes will be fully amortizing, with a weighted average life of over 10 years.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
SUMMARIZED QUARTERLY FINANCIAL DATA
(unaudited)

Summarized Quarterly Financial Data—(in millions, except per unit amounts)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year Ended December 31, 2020:				
Revenues	$ 1,718	$ 1,470	$ 982	$ 1,997
Income from operations	664	684	152	625
Net income (loss)	435	406	(67)	409
Net income (loss) per common unit—basic and diluted (1)	0.84	0.78	(0.08)	0.77
Year Ended December 31, 2019:				
Revenues	$ 1,749	$ 1,705	$ 1,476	$ 1,908
Income from operations	563	455	346	676
Net income	385	232	110	448
Net income per common unit—basic and diluted (1)	0.75	0.44	0.19	0.87

(1) The sum of the quarterly net income per common unit may not equal the full year amount as the undistributed income and loss allocations and computations of the weighted average common units outstanding for basic and diluted common units outstanding for each quarter and the full year are performed independently.

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, 2020, 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

On February 23, 2021, SPL and Cheniere Marketing entered into a letter agreement for the sale of up to thirty-one (31) cargoes to be scheduled for delivery between 2021 and 2026 at a price equal to 115% of Henry Hub plus $1.72 per MMBtu.

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, Oliver G. Richard, III and Vincent Pagano, Jr., 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 *http://www.cheniere.com/about-us/cheniere-partners/governance-and-ethics/.*

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, Eric Bensaude and Scott Peak, to approve LNG sales entered into between Cheniere Marketing and SPL.

Other

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

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

Directors and Executive Officers of Our General Partner

The following sets forth information, as of February 19, 2021, regarding the individuals who currently serve on the board of directors and as executive officers of our general partner. The appointments of Messrs. Henderson, Murski and Peak to the board of directors of our general partner were made 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.

Name	Age	Election Date	Position with Our General Partner
Jack A. Fusco	58	May 2016	Chairman of the Board and President and Chief Executive Officer
James R. Ball	70	September 2012	Director
Eric Bensaude	54	September 2016	Director
Zach Davis	36	August 2020	Director and Senior Vice President and Chief Financial Officer
Wallace C. Henderson	58	September 2020	Director
Lon McCain	72	March 2007	Director
Mark Murski	45	September 2020	Director
Vincent Pagano, Jr.	70	December 2012	Director
Scott Peak	40	September 2020	Director
Oliver G. Richard, III	68	September 2012	Director
Aaron Stephenson	65	November 2019	Director and Senior Vice President, Operations

Jack A. Fusco

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

Mr. Fusco serves as a director and President and Chief Executive Officer of Cheniere; Chief Executive Officer of SPL and a manager and President and Chief Executive Officer of the general partner of SPLNG. Mr. Fusco served as Chairman, President and Chief Executive Officer of Cheniere Energy Partners LP Holdings, LLC ("Cheniere Holdings") from June 2016 to September 2018. Mr. Fusco served as the Executive Chairman of Calpine Corporation ("Calpine") from May 2014 through May 2016, Chief Executive Officer of Calpine from August 2008 to May 2014, President of Calpine from August 2008 to December 2012 and director of Calpine from August 2008 to March 2018. From July 2004 to February 2006, Mr. Fusco served as the Chairman and Chief Executive Officer of Texas Genco LLC. From 2002 through July 2004, Mr. Fusco was an exclusive energy investment advisor for Texas Pacific Group. From November 1998 until February 2002, he served as founder, President and Chief Executive Officer of Orion Power Holdings, Inc. Prior to his founding of Orion Power Holdings, Inc., Mr. Fusco was a Vice President at Goldman Sachs Power, an affiliate of Goldman, Sachs & Co. Prior to joining Goldman, Sachs & Co., Mr. Fusco was employed by Pacific Gas & Electric Company or its affiliates in various engineering and management roles for approximately 13 years. Mr. Fusco obtained a Bachelor of Science degree in Mechanical Engineering from California State University, Sacramento. Mr. Fusco served as a director on the board of Foster Wheeler Ltd., a global engineering and construction contractor and power equipment supplier, until February 2009 and on the board of Graphics Packaging Holdings, a paper and packaging company, until 2008. 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 ("GSG"), from September 2011 to June 2013. From 1988 until August 2011, he also served as an executive director of GSG, a company he founded and where he spent his career advising on financing and developing many of the world's largest LNG projects. 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 a Master of Science from City University Business School (now Cass 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 directorship positions in the past five years.

Eric Bensaude

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

Mr. Bensaude joined Cheniere in September 2013 and currently serves as Managing Director, Commercial Operations and Asset Optimization of Cheniere Marketing Ltd., a subsidiary of Cheniere. Mr. Bensaude also serves as Senior Vice President, Commercial Operations of SPL. Mr. Bensaude has more than 20 years of experience in the energy, oil and natural gas trading and marketing business. Prior to joining Cheniere, Mr. Bensaude served as Head of Global LNG at EDF Trading where he set up and ran the LNG trading and marketing department and General Manager for natural gas and LNG origination. Prior to EDF Trading, Mr. Bensaude was an Associate at Booz Allen & Hamilton in the Energy Practice, working on a variety of gas & power assignments. Mr. Bensaude started his career in energy as a trader of middle distillates for Total and previously served as the representative for the French bank, Société Générale, in Canton, People's Republic of China. He held the position of Vice-Chairman of the European Federation of Energy Traders Gas Committee while at EDF Trading. Mr. Bensaude holds an MBA from ESSEC business school in France, and studied Mandarin at Paris 7 Jussieu. It was determined that Mr. Bensaude should serve as a director of our general partner because of his experience in the energy, oil and natural gas trading and marketing industry. Mr. Bensaude has not held any other directorship positions in the past five years.

Zach Davis

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

Mr. Davis currently serves as Senior Vice President and Chief Financial Officer of Cheniere. 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 13 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.

Wallace C. Henderson

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

Mr. Henderson has served as a Senior Managing Director at Blackstone Infrastructure Partners since January 2018 and leads the fund's investment activities in the midstream sector. From May 2011 to December 2017, Mr. Henderson served in various roles at EIG Global Energy Partners, LLC, most recently as Managing Director and member of the firm's Executive Committee. At EIG, Mr. Henderson led the company's global investment activities in midstream energy infrastructure, including a significant investment in Cheniere Energy's Corpus Christi LNG facility in 2015. Prior to joining EIG, Mr. Henderson was a senior financial consultant to Coskata, Inc., an energy technology company, from May 2009 until May 2011. Prior to Coskata, Mr. Henderson was an energy investment banker at UBS Investment Bank for five years following 18 years at Credit Suisse where he specialized in oil and gas project finance, corporate capital raising and mergers and acquisitions for large U.S. and international oil companies. Mr. Henderson currently serves as a director of Tallgrass Energy, L.P., a midstream energy infrastructure company. Mr. Henderson served as a director of Southcross Energy Partners GP, LLC, the general partner of Southcross Energy Partners, L.P., from August 2014 to November 2017. Mr. Henderson holds a Bachelor's degree in Economics from Kenyon College and a Master of Business Administration degree from Columbia University.

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 Contango Oil and Gas Company, a publicly traded oil and natural gas exploration and production company. Mr. McCain also currently serves on the board of directors of Continental Resources, Inc., a publicly traded oil and natural gas exploration and production company. Mr. McCain received a B.S. in Business Administration and a Masters of Business Administration/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.

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 his law degree, cum laude, from Harvard Law School and his 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. It was determined that Mr. Pagano should serve as a director of our general partner because of his capital markets expertise and his experience as an advisor to public companies on a variety of corporate matters.

Scott Peak

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

Mr. Peak is a Managing Partner and Chief Investment Officer for Brookfield Infrastructure, where he is responsible for utilities and energy infrastructure investments. Prior to joining Brookfield in January 2016, Mr. Peak spent almost a decade at Macquarie Group Ltd. based in New York and Houston focused on the infrastructure sector. Previously, Mr. Peak worked in the mergers and acquisitions group at Dresdner Kleinwort Wasserstein in New York. Mr. Peak holds a Master of Finance with distinction from INSEAD and a B.A. in Economics from Bates College.

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.

Aaron Stephenson

Senior Vice President, Operations and a Director of our general partner

Mr. Stephenson joined Cheniere in April 2013 as Director, Production, Sabine Pass Operations, leading the effort to prepare for liquefaction operations. In May 2016, he moved into the position of Vice President and General Manager for the Sabine Pass facility. Mr. Stephenson has over 40 years of experience in the energy industry, focusing for the past 17 years on LNG. He has worked in various locations around the world, including Yemen, London and Peru. Before joining Cheniere, he served as Plant Manager at Peru LNG. His professional experience includes filling the roles of LNG Plant Manager, E&P Manager, Commissioning Manager, Plant Engineering Manager and Project Engineer. Prior company affiliations include Cities Service Oil Co., Oxy USA and Hunt Oil Co. Mr. Stephenson has a B.S. in Mechanical Engineering from Lamar University. It was determined that Mr. Stephenson should serve as a director of our general partner because of his background in the LNG industry. Mr. Stephenson has not held any other directorship positions in 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 *http://www.cheniere.com/about-us/cheniere-partners/governance-and-ethics/*. 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.

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
Eric Bensaude
Zach Davis
Wallace C. Henderson
Lon McCain
Mark Murski
Vincent Pagano, Jr.
Scott Peak
Oliver G. Richard, III
Aaron Stephenson

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 2020.

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 the 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. Henderson serves as a Senior Managing Director at Blackstone Infrastructure Partners, Mr. Murski serves as a Managing Partner and Chief Operating Officer in the Americas for Brookfield Infrastructure and Mr. Peak serves as a Managing Partner and Chief Investment Officer for Brookfield Infrastructure. They do not receive additional compensation for service as directors.

Additionally, our former directors Philip Meier, John-Paul Munfa and Jamie Welch, who resigned from the board of directors of our general partner in September 2020, were previously appointed to the board 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. As such, Mr. Munfa and Mr. Welch did not receive any additional compensation for their service as directors. Philip Meier and Meier Consulting LLC entered into a letter agreement, dated June 14, 2013, as amended (the "Meier Consulting Letter Agreement"), with Blackstone CQP Holdco pursuant to which Mr. Meier agreed to provide consulting services to Blackstone CQP Holdco relating to the development, construction and operation of the Liquefaction Project. For a further description of the Meier Consulting Letter Agreement, see "Related Party Transactions-Arrangements involving Mr. Meier and Meier Consulting LLC" below. Mr. Meier received no additional compensation for his service as a director.

The following table shows the compensation paid for service as a member of the board of directors of our general partner for the 2020 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)	117,500	103,470	—	—	—	—	220,970
Eric Bensaude (2)	—	—	—	—	—	—	—
Zach Davis (2)	—	—	—	—	—	—	—
Wallace C. Henderson (4)	—	—	—	—	—	—	—
Lon McCain (5)	107,500	101,220	—	—	—	—	208,720
Mark Murski (4)	—	—	—	—	—	—	—
Vincent Pagano, Jr. (6)	102,500	112,710	—	—	—	—	215,210
Scott Peak (4)	—	—	—	—	—	—	—
Oliver G. Richard, III (7)	92,500	103,470	—	—	—	—	195,970
Aaron Stephenson (2)	—	—	—	—	—	—	—
Michael J. Wortley (2)	—	—	—	—	—	—	—
Philip Meier (8)	—	—	—	—	—	—	—
John-Paul Munfa (9)	—	—	—	—	—	—	—
Jamie Welch (9)	—	—	—	—	—	—	—

(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 2020. Mr. Bensaude served as an officer of Cheniere Marketing Ltd., a subsidiary of Cheniere during fiscal year 2020. Mr. Davis served as an executive officer of our general partner and as an executive officer of Cheniere from since August 6, 2020. Mr. Stephenson served as an officer of our general partner and as an executive officer of Cheniere during fiscal year 2020. Mr. Wortley served as an executive officer of our general partner and as an executive officer of Cheniere until his resignation on August 6, 2020. 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 2020 with a grant date fair value of $103,470. In addition, Mr. Ball received $51,735 in cash and 1,500 common units on account of 3,000 phantom units granted in earlier years that vested in 2020. As of December 31, 2020, he held 7,500 phantom units and 6,450 common units for a total of 13,950 units.

(4) Mr. Henderson is a Senior Managing Director at Blackstone Infrastructure Partners, Mr. Murski is a Managing Partner and Chief Operating Officer in the Americas for Brookfield Infrastructure and Mr. Peak is a Managing Partner and Chief Investment Officer for Brookfield Infrastructure. They do not receive additional compensation for service as directors.

(5) Mr. McCain was granted 3,000 phantom units in 2020 with a grant date fair value of $101,220. In addition, Mr. McCain received $50,610 in cash and 1,500 common units on account of 3,000 phantom units granted in earlier years that vested in 2020. As of December 31, 2020, he held 7,500 phantom units and 8,250 common units for a total of 15,750 units.

(6) Mr. Pagano was granted 3,000 phantom units in 2020 with a grant date fair value of $112,710. In addition, Mr. Pagano received $56,355 in cash and 1,500 common units on account of 3,000 phantom units granted in earlier years that vested in 2020. As of December 31, 2020, he held 7,500 phantom units and 7,125 common units for a total of 14,625 units.

(7) Mr. Richard was granted 3,000 phantom units in 2020 with a grant date fair value of $103,470. In addition, Mr. Richard received $38,801 in cash and 1,875 common units on account of 3,000 phantom units granted in earlier years

that vested in 2020. As of December 31, 2020, he held 7,500 phantom units and 11,250 common units for a total of 18,750 units.

(8) Effective as of September 24, 2020, Mr. Meier resigned as a member of the board of directors of our general partner. Mr. Meier was compensated by Blackstone CQP Holdco pursuant to the Meier Consulting Letter Agreement and received no additional compensation for service as a director. For a further description of the Meier Consulting Letter Agreement, see “Related Party Transactions-Arrangements involving Mr. Meier and Meier Consulting LLC” below.

(9) Effective as of September 24, 2020, Messrs. Munfa and Welch resigned as members of the board of directors of our general partner. Mr. Munfa was a Managing Director in the Private Equity Group of Blackstone Group, and Mr. Welch served as a Senior Advisor to Blackstone Group. They did not receive additional compensation for their service as directors.

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 19, 2021, 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 19, 2021:

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%
The Blackstone Group Inc. (2)	206,080,463	43%	42%
Brookfield Asset Management Inc. (3)	204,321,313	42%	41%

* Less than 1%

(1) Cheniere Energy, Inc. also owns 9,877,677 of our general partner units.

(2) Information is based on the Schedule 13D/A filed with the SEC on September 28, 2020 by BX Rockies Platform Co LLC (record holder of 2,250,419 common units), Blackstone CQP Common Holdco L.P. (record holder of 2,011,447 common units), Blackstone CQP Common Holdco GP LLC, BX CQP Common Holdco Parent L.P., BX CQP Common Holdco Parent GP LLC, Blackstone CQP Holdco LP (record holder of 185,808,450 common units), Blackstone CQP Holdco II GP LLC, Blackstone CQP FinanceCo LP, Blackstone CQP Holdco GP LLC, BX CQP Target Holdco L.L.C., BIP Chinook Holdco L.L.C., BIP-V Chinook Holdco L.L.C. (record holder of 13,170,436 common units), BIP Holdings Manager L.L.C., Blackstone Infrastructure Associates L.P., BIA GP L.P., BIA GP L.L.C., BX Rockies Platform Co Holdings Manager L.L.C., BX CQP Common Holdco Holdings Manager L.L.C., BX CQP SuperHoldCo Holdings Manager L.L.C., Blackstone Management Associates VI L.L.C., Blackstone Energy Management Associates L.L.C., BMA VI L.L.C., Blackstone EMA L.L.C., Blackstone Holdings III L.P., Blackstone Holdings III GP L.P, Blackstone Holdings III GP Management L.L.C., GSO Credit-A Partners LP (record holder of 953,855 common units), GSO Credit-A Associates LLC, GSO Palmetto Opportunistic Investment Partners LP (record holder of 953,855 common units), GSO Palmetto Opportunistic Associates LLC, GSO Credit Alpha Fund AIV-2 LP (record holder of 462,922 common units), GSO Credit Alpha Associates LLC, GSO Holdings I L.L.C., Blackstone Holdings II L.P., Blackstone Holdings I/II GP L.L.C., The Blackstone Group Inc., Blackstone Group Management L.L.C. and Stephen A. Schwarzman, and filings of Form 4 on December 31, 2020, January 5, 2021 and January 6, 2021 by BIP Holdings Manager, L.L.C., BIA GP L.L.C., BIA GP L.P., Blackstone Infrastructure Associates L.P., BX Rockies Platform Co LLC, BIP Chinook Holdco L.L.C. (record holder of 138,772 common units) and BIP-V Chinook Holdco II L.L.C. (record holder of 48,544 common units). In addition, Harvest Fund Advisors LLC, an indirect subsidiary of The Blackstone Group Inc., is the beneficial owner of 281,763 common units. The address of the various persons identified in this footnote is 345 Park Avenue, New York, New York 10154.

(3) Information is based on the Schedule 13D/A filed with the SEC on September 30, 2020 by Brookfield Asset Management Inc. (“Brookfield”), BIF IV Cypress Aggregator (Delaware) LLC (“BIF Aggregator”), Brookfield Infrastructure Fund IV GP LLC (“BIF”), Brookfield Asset Management Private Institutional Capital Adviser (Canada), L.P. (“BAMPIC Canada”) and Partners Limited (“Partners”). Investment funds managed by Brookfield Public Securities Group LLC are the beneficial owners of 1,080,561 common units. 2,011,447 of the Common Units reported herein as being beneficially owned by the Reporting Persons are directly held by BX Rockies Platform Co LLC, a Delaware limited liability company (“BX Rockies”). 185,808,450 of the Common Units reported herein as being beneficially owned by the Reporting Persons are directly held by Blackstone CQP Holdco LP, a Delaware limited partnership (“Blackstone Holdco”). 2,250,419 of the Common Units reported herein as being beneficially owned by the Reporting Persons are directly held by Blackstone CQP Common Holdco L.P., a Delaware limited partnership (“Blackstone Common Holdco”). 13,170,436 of the Common Units reported herein as being beneficially owned by the Reporting Persons are directly held by BIP-V Chinook Holdco L.L.C., a Delaware limited liability company (“BIP-V”). BX CQP Target Holdco L.L.C. (“Target Holdco”) is the indirect equityholder of all of the equity interests in each of BX Rockies, Blackstone Common Holdco and Blackstone Holdco and, by virtue of its relationship with BIP-V, may be deemed to share beneficial ownership over the Common Units held 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 BIF and BAMPIC Canada. As a result, BIF IV Cypress Aggregator, BIF, BAMPIC Canada, Brookfield and Partners may be deemed to beneficially own the Common Units held of record by each of BX Rockies, Blackstone Common Holdco, Blackstone Holdco 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 19, 2021, 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 19, 2021, the current directors and executive officers of Cheniere Partners beneficially owned an aggregate of 33,075 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 19, 2021, 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 19, 2021, Cheniere Energy, Inc. had 254 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 (1)	—	— %	1,040,540 (1)	*%
Michael J. Wortley (2)	—	—	551,798	*
Zach Davis	—	—	110,492	*
Eric Bensaude	—	—	—	—
Aaron Stephenson	—	—	76,895	*
James R. Ball	6,450	*	—	—
Wallace C. Henderson (3)	—	—	—	—
Lon McCain	8,250	*	—	—
Mark Murski (3)	—	—	—	—
Vincent Pagano, Jr.	7,125	*	—	—
Scott Peak (3)	—	—	—	—
Oliver G. Richard, III	11,250	*	—	—
All current directors and executive officers as a group (11 persons) (4)	33,075	*%	1,227,927	*%

* Less than 1%

(1) Includes 198,778 shares held by trust.

(2) The number of shares set forth for Mr. Wortley is based on the Form 4 filed on February 18, 2020 for Mr. Wortley. Mr. Wortley ceased to be employed by our general partner on August 31, 2020 and is no longer required to report his holdings in Cheniere Partner's or Cheniere Energy Inc.'s securities pursuant to Section 16(a) of the Securities Act.

(3) Messrs. Henderson, Murski and Peak 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.

(4) Excludes shares owned by Mr. Wortley, who was no longer an executive officer of our general partner on February 19, 2021.

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, 2020 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	1,194,500
Total	15,000	N/A	1,194,500

(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 Part II, Item 5, 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 Company 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.

Arrangements involving Mr. Meier and Meier Consulting LLC

As noted above, Blackstone CQP Holdco, our former director Mr. Meier and Meier Consulting LLC entered into the Meier Consulting Letter Agreement, pursuant to which Mr. Meier agreed to provide consulting services to Blackstone CQP Holdco relating to the development, construction and operation of the Liquefaction Project. As compensation for the consulting services, Blackstone CQP Holdco agreed to pay Mr. Meier an annual base consulting fee and an annual performance consulting fee in Blackstone CQP Holdco's discretion. In 2020, Blackstone CQP Holdco paid Mr. Meier $541,667 as a base consulting fee. Mr. Meier resigned from the board of directors of our general partner effective September 24, 2020.

We entered into a letter agreement with Blackstone CQP Holdco (the "Blackstone Consultant Letter Agreement"), dated June 23, 2013, pursuant to which we agreed to reimburse Blackstone CQP Holdco for (a) 25% of the fees of Mr. Meier described in the Meier Consulting Letter Agreement and (b) 25% of the expenses of Mr. Meier incurred in connection with his consulting services relating to the Liquefaction Project which are either to be paid or reimbursed by Blackstone CQP Holdco pursuant to the Meier Consulting Letter Agreement. We did not reimburse Blackstone CQP Holdco for any fees and expenses with respect to 2020 under the Blackstone Consultant Letter Agreement.

Independent Directors

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

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

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

KPMG LLP served as our independent auditor for the fiscal years ended December 31, 2020 and 2019. The following table sets forth the fees paid to KPMG LLP for professional services rendered for 2020 and 2019 (in millions):

	Fiscal 2020	Fiscal 2019
Audit Fees	$ 3	$ 3

Audit Fees—Audit fees for 2020 and 2019 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 2020 and 2019.

Tax Fees—There were no tax fees in 2020 and 2019.

Other Fees—There were no other fees in 2020 and 2019.

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, 2020 and 2019 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 Company or the other parties to the agreements. Investors should not rely on them as statements of fact.

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
2.1	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 LNG-LP, LLC, effective as of March 26, 2007	Cheniere Partners	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	Cheniere Partners	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	Cheniere Partners (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	Cheniere Partners	8-K	3.1	2/21/2017
3.3	Certificate of Formation of Cheniere Partners GP	Cheniere Partners (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	Cheniere Partners	8-K	3.2	8/9/2012
4.1	Form of common unit certificate (Included as Exhibit A to Exhibit 3.2 above)	Cheniere Partners	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	Cheniere Partners	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	Cheniere Partners	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	Cheniere Partners	8-K	4.1.2	4/16/2013
4.5	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.4 above)	Cheniere Partners	8-K	4.1.2	4/16/2013
4.6	Third Supplemental Indenture, dated as of November 25, 2013, between SPL and The Bank of New York Mellon, as Trustee	Cheniere Partners	8-K	4.1	11/25/2013
4.7	Form of 6.25% Senior Secured Note due 2022 (Included as Exhibit A-1 to Exhibit 4.6 above)	Cheniere Partners	8-K	4.1	11/25/2013
4.8	Fourth Supplemental Indenture, dated as of May 20, 2014, between SPL and The Bank of New York Mellon, as Trustee	Cheniere Partners	8-K	4.1	5/22/2014
4.9	Form of 5.750% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.8 above)	Cheniere Partners	8-K	4.1	5/22/2014
4.10	Fifth Supplemental Indenture, dated as of May 20, 2014, between SPL and The Bank of New York Mellon, as Trustee	Cheniere Partners	8-K	4.2	5/22/2014
4.11	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.10 above)	Cheniere Partners	8-K	4.2	5/22/2014
4.12	Sixth Supplemental Indenture, dated as of March 3, 2015, between SPL and The Bank of New York Mellon, as Trustee	Cheniere Partners	8-K	4.1	3/3/2015
4.13	Form of 5.625% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.12 above)	Cheniere Partners	8-K	4.1	3/3/2015
4.14	Seventh Supplemental Indenture, dated as of June 14, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere Partners	8-K	4.1	6/14/2016
4.15	Form of 5.875% Senior Secured Note due 2026 (Included as Exhibit A-1 to Exhibit 4.13 above)	Cheniere Partners	8-K	4.1	6/14/2016
4.16	Eighth Supplemental Indenture, dated as of September 19, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere Partners	8-K	4.1	9/23/2016
4.17	Ninth Supplemental Indenture, dated as of September 23, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere Partners	8-K	4.2	9/23/2016
4.18	Form of 5.00% Senior Secured Note due 2027 (Included as Exhibit A-1 to Exhibit 4.17 above)	Cheniere Partners	8-K	4.2	9/23/2016
4.19	Tenth Supplemental Indenture, dated as of March 6, 2017, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere Partners	8-K	4.1	3/6/2017
4.20	Form of 4.200% Senior Secured Note due 2028 (Included as Exhibit A-1 to Exhibit 4.19 above)	Cheniere Partners	8-K	4.1	3/6/2017

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
4.21	Eleventh Supplemental Indenture, dated as of May 8, 2020, betweenSPL and The Bank of New York Mellon, as Trustee under the Indenture	SPL	8-K	4.1	5/8/2020
4.22	Form of 4.500% Senior Secured Note due 2030 (Included as Exhibit A-1 to Exhibit 4.21 above)	SPL	8-K	4.1	5/8/2020
4.23	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	Cheniere Partners	8-K	4.1	2/27/2017
4.24	Form of 5.00% Senior Secured Note due 2037 (Included as Exhibit A-1 to Exhibit 4.23 above)	Cheniere Partners	8-K	4.1	2/27/2017
4.25	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	Cheniere Partners	8-K	4.1	9/18/2017
4.26	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	Cheniere Partners	8-K	4.2	9/18/2017
4.27	Form of 5.250% Senior Note due 2025 (Included as Exhibit A-1 to Exhibit 4.26 above)	Cheniere Partners	8-K	4.2	9/18/2017
4.28	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	Cheniere Partners	8-K	4.1	9/12/2018
4.29	Form of 5.625% Senior Note due 2026 (Included as Exhibit A-1 to Exhibit 4.28 above)	Cheniere Partners	8-K	4.1	9/12/2018
4.30	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	Cheniere Partners	8-K	4.1	9/12/2019
4.31	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	Cheniere Partners	10-Q	4.1	11/6/2020
4.32	Description of the Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934	Cheniere Partners	10-K	4.30	2/25/2020
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	Cheniere Partners	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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
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	Cheniere Partners	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	Cheniere Partners	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	Cheniere Partners	8-K	10.3	3/23/2020
10.18	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	Cheniere Partners	8-K	10.1	6/3/2019
10.19	Registration Rights Agreement, dated as of May 8, 2020, between SPL and Morgan Stanley & Co. LLC	SPL	8-K	10.1	5/8/2020
10.20†	Cheniere Energy Partners, L.P. 2007 Long-Term Incentive Plan	Cheniere Partners	8-K	10.3	3/26/2007
10.21†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (2012 Reload Award)	Cheniere Partners	10-Q	10.9	11/2/2012
10.22†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan	Cheniere Partners	10-Q	10.8	11/2/2012
10.23†	Form of Amendment to Phantom Units Agreement	Cheniere Partners	10-Q	10.7	11/2/2012
10.24†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Units Settlement)	Cheniere Partners	10-K	10.41	2/20/2015
10.25†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Reload Units Settlement)	Cheniere Partners	10-K	10.42	2/20/2015
10.26†	Form of Indemnification Agreement for officers and/or directors of Cheniere Partners GP	Cheniere Partners	10-K	10.42	2/19/2016
10.27	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.)	Cheniere Partners	8-K	10.1	11/9/2018
10.28	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: the Change Order CO-00001 Modifications to Insurance Language Change Order, dated June 3, 2019	Cheniere Partners	10-Q	10.4	8/8/2019

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.29	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	Cheniere Partners	10-Q	10.2	11/1/2019
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.: (i) the Change Order CO-00011 Insurance Provisional Sum Interim Adjustment, dated October 1, 2019 and (ii) the Change Order CO-00012 Replacement of Timber Piles with Pre-Stressed Concrete Piles, dated October 30, 2019	Cheniere Partners	10-K	10.34	2/25/2020
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-00013 Cost to Comply with SPL FTZ (FTZ entries, bonded transports and receipts for AG Pipe Spools Only), dated February 10, 2020, (ii) the Change Order CO-00014 Permanent Access Road to Third Berth, dated February 10, 2020, (iii) the Change Order CO-00015 Modifications to Schedule Bonus Language, dated February 10, 2020, (iv) the Change Order CO-00016 LNG Berth 3 LNTP No 3, dated January 31, 2020 and (v) the Change Order CO-00017 Construction Doc Fender Guards and LP Fuel Gas Overpressure Interlock, dated March 18, 2020	Cheniere Partners	10-Q	10.4	4/30/2020
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-00018 Electrical Studies for GTG Grid Modification, dated April 2, 2020, (ii) the Change Order CO-00019 Third Berth - Change in 5kV Electrical Tie-In, dated April 30, 2020, (iii) the Change Order CO-00020 LNG Berth 3 LNTP No. 4, dated May 4, 2020, (iv) the Change Order CO-00021 Train 6 P1601 A/B/ Flange Changes, dated May 27, 2020 and (v) the Change Order CO-00022 Train 6 H2S Skid Modifications to Level Transmitters & GTG Pressure Range Change on PT-573 A/B, dated June 4, 2020	Cheniere Partners	10-Q	10.2	8/6/2020

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
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-00023 Third Berth Vapor Fence Provisional Sum Scope Removal and Closeout, dated June 22, 2020, (ii) the Change Order CO-00024 Train 6 Thermowell Upgrades, dated June 22, 2020, (iii) the Change Order CO-00025 Third Berth Bubble Curtain, dated June 22, 2020, (iv) the Change Order CO-00026 Third Berth Fuel Provisional Sum Closure Change Order, dated July 14, 2020, (v) the Change Order CO-00027 Third Berth Currency Provisional Sum Closure Change Order, dated July 20, 2020, (vi) the Change Order CO-00028 Train 6 Hot Oil WHRU PSV Bypass, dated August 11, 2020 and (vii) the Change Order CO-00029 Change in Law IMO 2020 Regulatory Change – Low Sulphur Emissions on Marine Vessels, dated August 25, 2020	Cheniere Partners	10-Q	10.1	11/6/2020
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 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				
10.35	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)	Cheniere Partners	8-K	10.1	11/21/2011
10.36	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)	Cheniere Partners	10-Q	10.1	5/3/2013
10.37	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
10.38	LNG Sale and Purchase Agreement (FOB), dated December 11, 2011, between SPL (Seller) and GAIL (India) Limited (Buyer)	Cheniere Partners	8-K	10.1	12/12/2011
10.39	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between SPL (Seller) and GAIL (India) Limited (Buyer)	Cheniere Partners	10-K	10.18	2/22/2013
10.40	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated January 25, 2012, between SPL (Seller) and BG Gulf Coast LNG, LLC (Buyer)	Cheniere Partners	8-K	10.1	1/26/2012
10.41	LNG Sale and Purchase Agreement (FOB), dated January 30, 2012, between SPL (Seller) and Korea Gas Corporation (Buyer)	Cheniere Partners	8-K	10.1	1/30/2012
10.42	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between SPL (Seller) and Korea Gas Corporation (Buyer)	Cheniere Partners	10-K	10.19	2/22/2013
10.43	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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.44	Letter agreement, dated December 8, 2016, amending the Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between SPL and Cheniere Marketing International LLP (as assignee of Cheniere Marketing, LLC)	SPL	10-K	10.14	2/24/2017
10.45	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	Cheniere Partners	10-Q	10.1	5/9/2019
10.46	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).	Cheniere Partners	8-K	10.1	12/9/2020
10.47*	Letter Agreement, dated February 23, 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)				
10.48	Management Services Agreement, dated May 14, 2012, by and between Cheniere Terminals and SPL	Cheniere Partners	8-K	10.6	5/15/2012
10.49	Amendment to Management Services Agreement, dated September 28, 2015, between Cheniere Terminals and SPL	SPL	10-Q/A	10.8	11/9/2015
10.50	Amended and Restated Management Services Agreement, dated as of August 9, 2012, by and between Cheniere Terminals and SPLNG	Cheniere Partners	10-Q	10.6	11/2/2012
10.51	Management Services Agreement, dated May 27, 2013, by and between Cheniere Terminals and CTPL	Cheniere Partners	10-Q	10.2	8/2/2013
10.52	Operation and Maintenance Agreement (Sabine Pass Liquefaction Facilities), dated May 14, 2012, by and between Cheniere LNG O&M Services, LLC, Cheniere Partners GP and SPL	Cheniere Partners	8-K	10.5	5/15/2012
10.53	Assignment and Assumption Agreement (Sabine Pass Liquefaction O&M Agreement), dated as of November 20, 2013, by and between Cheniere Partners GP and Cheniere Investments	Cheniere Holdings	S-1/A	10.76	12/2/2013
10.54	Amendment to Operation and Maintenance Agreement (Sabine Pass Liquefaction Facilities), dated September 28, 2015, by and among Cheniere LNG O&M Services, LLC, Cheniere Investments and SPL	SPL	10-Q/A	10.7	11/9/2015
10.55	Amended and Restated Operation and Maintenance Agreement (Sabine Pass LNG Facilities), dated as of August 9, 2012, by and among Cheniere Partners GP, Cheniere LNG O&M Services, LLC, and SPLNG	Cheniere Partners	10-Q	10.5	11/2/2012
10.56	Assignment and Assumption Agreement (Sabine Pass LNG O&M Agreement), dated as of November 20, 2013, by and between Cheniere Partners GP and Cheniere Investments	Cheniere Holdings	S-1/A	10.75	12/2/2013
10.57	Amended and Restated Management and Administrative Services Agreement, dated as of August 9, 2012, by and between Cheniere Terminals, the Partnership and Cheniere	Cheniere Partners	10-Q	10.4	11/2/2012
10.58	Amended and Restated Operation and Maintenance Services Agreement (Cheniere Creole Trail Pipeline), dated May 27, 2013, by and between CTPL and Cheniere Partners GP	Cheniere Partners	10-Q	10.1	8/2/2013
10.59	Assignment and Assumption Agreement (Creole Trail O&M Agreement), dated as of November 20, 2013, between Cheniere Partners GP and Cheniere Investments	Cheniere Holdings	S-1/A	10.74	12/2/2013
10.60	Cooperative Endeavor Agreement & Payment in Lieu of Tax Agreement with eleven Cameron Parish taxing authorities, dated October 23, 2007, by and between Cheniere Marketing, Inc. and SPLNG	Cheniere	10-Q	10.7	11/6/2007
10.61	Amended and Restated Services and Secondment Agreement, dated as of August 9, 2012, between Cheniere LNG O&M Services, LLC and Cheniere Partners GP	Cheniere Partners	10-Q	10.3	11/2/2012

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.62	Assignment and Assumption Agreement (Services and Secondment Agreement), dated as of November 20, 2013, by and between Cheniere Partners GP and Cheniere Investments	Cheniere Holdings	S-1/A	10.73	12/2/2013
10.63	Investors' and Registration Rights Agreement, dated as of July 31, 2012, by and among Cheniere, Cheniere Partners GP, the Partnership, Cheniere Class B Units Holdings, LLC, Blackstone CQP Holdco LP and the other investors party thereto from time to time	Cheniere Partners	8-K	10.1	8/6/2012
21.1*	Subsidiaries of the Partnership				
22.1	List of Issuers and Guarantor Subsidiaries	Cheniere Partners	10-Q	22.1	8/6/2020
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				
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), Cheniere Partners (SEC File No. 001-33366), 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.

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED STATEMENTS OF INCOME
(in millions)

	Year Ended December 31,		
	2020	2019	2018
Operating costs and expenses			
General and administrative expense	$ 3	$ 3	$ 4
General and administrative expense—affiliate	14	13	12
Depreciation and amortization expense	3	3	2
Total operating costs and expenses	20	19	18
Other income			
Interest expense, net of capitalized interest	(217)	(174)	(139)
Loss on modification or extinguishment of debt	—	(13)	(12)
Derivative gain, net	—	—	14
Other income	7	21	13
Equity income of affiliates	1,413	1,360	1,416
Total other income	1,203	1,194	1,292
Net income	$ 1,183	$ 1,175	$ 1,274

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

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED BALANCE SHEETS
(in millions)

	December 31,	
	2020	2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,208	$ 1,778
Other current assets	1	—
Total current assets	1,209	1,778
Property, plant and equipment, net	79	79
Debt issuance costs, net	7	9
Investment in affiliates	3,359	2,963
Total assets	$ 4,654	$ 4,829
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accrued liabilities	$ 52	$ 56
Due to affiliates	3	3
Total current liabilities	55	59
Long-term debt, net	4,060	4,055
Partners' equity	539	715
Total liabilities and partners' equity	$ 4,654	$ 4,829

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

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2020	2019	2018
Cash flows provided by operating activities	$ 1,190	$ 1,220	$ 714
Cash flows from investing activities			
Property, plant and equipment, net	(3)	(2)	—
Investments in subsidiaries	(689)	(1,273)	(304)
Distributions received from affiliates	291	853	454
Net cash provided by (used in) investing activities	(401)	(422)	150
Cash flows from financing activities			
Proceeds from issuance of debt	—	2,230	1,100
Repayments of debt	—	(730)	(1,090)
Debt issuance and deferred financing costs	—	(35)	(8)
Debt extinguishment costs	—	—	(7)
Distributions to owners	(1,359)	(1,260)	(1,113)
Other	—	(4)	—
Net cash provided by (used in) financing activities	(1,359)	201	(1,118)
Net increase (decrease) in cash, cash equivalents and restricted cash	(570)	999	(254)
Cash, cash equivalents and restricted cash—beginning of period	1,778	779	1,033
Cash and cash equivalents—end of period	$ 1,208	$ 1,778	$ 779

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

CHENIERE ENERGY PARTNERS, L.P.

NOTES TO CONDENSED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

In the Condensed Financial Statements, Cheniere Partners' investments in affiliates are presented at the net amount attributable to Cheniere Partners. 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 Cheniere Partners' operating, investing and financing activities are conducted by its affiliates. The Condensed Financial Statements should be read in conjunction with Cheniere Partners' Consolidated Financial Statements.

Recent Accounting Standards

In March 2020, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("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 optional expedients were available to be used upon issuance of this guidance but we have not yet applied the guidance because we have not yet modified any of our existing contracts for reference rate reform. Once we apply an optional expedient to a modified contract and adopt this standard, the guidance will be applied to all subsequent applicable contract modifications until December 31, 2022, at which time the optional expedients are no longer available.

NOTE 2—DEBT

As of December 31, 2020 and 2019, our debt consisted of the following (in millions):

	December 31,	
	2020	2019
Long-term debt:		
4.500% to 5.625% senior notes due between 2025 and 2029 and credit facilities ("2019 CQP Credit Facilities")	$ 4,100	$ 4,100
Unamortized debt issuance costs	(40)	(45)
Total long-term debt, net	$ 4,060	$ 4,055

Below is a schedule of future principal payments that we are obligated to make on our outstanding debt at December 31, 2020 (in millions):

Years Ending December 31,	Principal Payments
2021	$ —
2022	—
2023	—
2024	—
2025	1,500
Thereafter	2,600
Total	$ 4,100

CHENIERE ENERGY PARTNERS, L.P.

NOTES TO CONDENSED FINANCIAL STATEMENTS—CONTINUED

NOTE 3—SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2020	2019	2018
Cash paid during the period for interest, net of amounts capitalized	$ 213	$ 151	$ 115
Non-cash capital distributions (1)	1,413	1,360	1,416

(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 23, 2021

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 23, 2021
/s/ Zach Davis Zach Davis	Senior Vice President and Chief Financial Officer, Director (Principal Financial Officer)	February 23, 2021
/s/ Leonard E. Travis Leonard E. Travis	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 23, 2021
/s/ James R. Ball James R. Ball	Director	February 23, 2021
/s/ Eric Bensuade Eric Bensuade	Director	February 23, 2021
/s/ Wallace C. Henderson Wallace C. Henderson	Director	February 23, 2021
/s/ Lon McCain Lon McCain	Director	February 23, 2021
/s/ Mark Murski Mark Murski	Director	February 23, 2021
/s/ Vincent Pagano Jr. Vincent Pagano Jr.	Director	February 23, 2021
/s/ Scott Peak Scott Peak	Director	February 23, 2021
/s/ Oliver G. Richard, III Oliver G. Richard, III	Director	February 23, 2021
/s/ Aaron Stephenson Aaron Stephenson	Director	February 23, 2021

Exhibit 10.34

CHANGE ORDER

Third Berth Soil Preparation Provisional Sum Interim Adjustment Change Order

PROJECT NAME: Sabine Pass LNG Stage 4 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00030

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: September 16, 2020

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. Pursuant to the instructions in the Soils Preparation Provisional Sum in Section 2.6 of Attachment EE, Schedule EE-4 of the Agreement, this Change Order amends the Soils Preparation Provisional Sum amount based on the Final Soils Preparation Basis Documents.

2. The Soils Preparation Provisional Sum in Section 2.6 of Attachment EE, Schedule EE-4 of the Agreement prior to this Change Order was Five Million, Six Hundred Seventeen Thousand U.S. Dollars (U.S. $5,617,000). The Soils Preparation Provisional Sum is hereby increased by One Million, Nine Hundred Eighty-Three Thousand, Two Hundred Sixty U.S. Dollars (U.S. $1,983,260) and the new value as amended by this Change Order shall be Seven Million, Six Hundred Thousand, Two Hundred Sixty U.S. Dollars (U.S. $7,600,260).

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

4. Schedule C-1 (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.

5. The final adjustment to the Soils Preparation Provisional Sum actual costs incurred will be made in accordance with Section 2.6 of Attachment EE, Schedule EE-4 of the Agreement.

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)	$	(16,842,054)
3.	The Contract Price Applicable to Subproject 6(a) prior to this Change Order was..................................	$	2,000,050,519
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..................	$	2,000,050,519

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)	$	6,111,453
9.	The Contract Price Applicable to Subproject 6(b) prior to this Change Order was.................................	$	463,807,453
10.	The Contract Price Applicable to Subproject 6(b) will be unchanged by this Change Order..................	$	—
11.	The Provisional Sum Applicable to Subproject 6(b) will be increased by this Change Order.................	$	1,983,260
12.	The Contract Price Applicable to Subproject 6(b) including this Change Order will be..................	$	465,790,713

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)...	$	2,463,857,972
15.	The Contract Price will be increased by this Change Order in the amount of (add lines 4, 5, 10 and 11).........	$	1,983,260
16.	The new Contract Price including this Change Order will be (add lines 14 and 15)	$	2,465,841,232

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: ____ 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: /s/MDR Contractor /s/DC 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/ Maurissa D. Rogers
Owner	Contractor
David Craft	Maurissa D. Rogers
Name	Name
SVP E&C	Sr Project Manager, PVP
Title	Title
September 29, 2020	September 17, 2020
Date of Signing	Date of Signing

CHANGE ORDER

Provisional Sum Consolidation (PAB, Taxes & Insurance)

PROJECT NAME: Sabine Pass LNG Stage 4 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00031

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: October 02, 2020

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 6.2 of the Agreement (*Change Orders Requested by Contractor*), the Parties agree this Change Order combines the following Provisional Sum Items from Schedule EE-4 of Attachment EE of the Agreement for Subproject 6(b) to Schedule EE-2 of Attachment EE of the Agreement for Subproject 6(a).

1.1. Louisiana Sales and Use Tax Provisional Sum

The current Aggregate Provisional Sum in Section 2.1 of Schedule EE-2 of Attachment EE of the Agreement contains a Provisional Sum of Thirty-Five Million, One Hundred Ninety-Five Thousand, Seven Hundred Ninety-Two U.S. Dollars (U.S. $35,195,792) for Louisiana Sales and Use Taxes arising in connection with the Work ("***Louisiana Sales and Use Tax Provisional Sum***") for Subproject 6(a).

The current Aggregate Provisional Sum in Section 2.1 of Schedule EE-3 of Attachment EE of the Agreement contains a Provisional Sum of Seven Million, Three Hundred Forty-Eight Thousand U.S. Dollars (U.S. $7,348,000) for Louisiana Sales and Use Taxes arising in connection with the Work ("***Louisiana Sales and Use Tax Provisional Sum***") for Subproject 6(b).

By way of this Change Order, the Louisiana Sales and Use Tax Provisional Sum in Section 2.1 of Schedule EE-3 of Attachment EE of the Agreement shall be decreased by Seven Million, Three Hundred Forty-Eight Thousand U.S. Dollars (U.S. $7,348,000), and transferred to the Louisiana Sales and Use Tax Provisional Sum in Section 2.1 of Schedule EE-2 of Attachment EE of the Agreement, and the new value of the Aggregate Louisiana Sales and Use Tax Provisional Sum is Forty-Two Million, Five Hundred Forty-Three Thousand, Seven Hundred Ninety-Two U.S. Dollars (U.S. $42,543,792).

1.2. Performance and Attendance Bonus ("PAB") Provisional Sum

The current Aggregate Provisional Sum in Section 2.2 of Schedule EE-2 of Attachment EE of the Agreement contains a Provisional Sum of Thirty-Seven Million U.S. Dollars (U.S. $37,000,000) for craft compensation in order to attract and retain qualified craft ("***Performance and Attendance Bonus Provisional Sum***") for Subproject 6(a).

The current Aggregate Provisional Sum in Section 2.2 of Schedule EE-3 of Attachment EE of the Agreement contains a Provisional Sum of Five Million U.S. Dollars (U.S. $5,000,000) for craft compensation in order to attract and retain qualified craft ("***Performance and Attendance Bonus Provisional Sum***") for Subproject 6(b).

By way of this Change Order, the Performance and Attendance Bonus Provisional Sum Provisional Sum in Section 2.2 of Schedule EE-3 of Attachment EE of the Agreement shall be decreased by Five Million U.S. Dollars (U.S. $5,000,000), and transferred to the Performance and Attendance Bonus Provisional Sum in Section 2.2 of Schedule EE-2 of Attachment EE of the Agreement, and the new value of the Aggregate Performance and Attendance Bonus Provisional Sum is Forty-Two Million U.S. Dollars (U.S. $42,000,000).

1.3. Insurance Provisional Sum

The current Aggregate Provisional Sum in Section 2.3 of Schedule EE-2 of Attachment EE of the Agreement Aggregate Provisional Sum contains a Provisional Sum of Thirty-Four Million, Two Hundred Forty-Four Thousand, Eight Hundred Fifty U.S. Dollars (U.S.$34,244,850) ("***Insurance Provisional Sum***") for the cost of insurance premiums for Subproject 6(a).

The current Aggregate Provisional Sum in Section 2.3 of Schedule EE-3 of Attachment EE of the Agreement Aggregate Provisional Sum contains a Provisional Sum of Five Million, Five Hundred Ninety-Six Thousand U.S. Dollars (U.S. $5,596,000) (“***Insurance Provisional Sum***”) for the cost of insurance premiums for Subproject 6(b).

By way of this Change Order, the Insurance Provisional Sum Provisional Sum in Section 2.3 of Schedule EE-3 of Attachment EE of the Agreement shall be decreased by Five Million, Five Hundred Ninety-Six Thousand U.S. Dollars (U.S. $5,596,000), and transferred to the Insurance Provisional Sum in Section 2.3 of Schedule EE-2 of Attachment EE of the Agreement, and the new value of the Aggregate Insurance Provisional Sum is Thirty-Nine Million, Eight Hundred Forty Thousand, Eight Hundred Fifty U.S. Dollars (U.S. $39,840,850).

2. The summary of costs associated with this Change Order is provided in Exhibit A of this Change Order.

3. Schedule C-3 (Milestone Payment Schedule for Subproject 6(b)) and Schedule C-4 (Monthly Payment Schedule for Subproject 6(b)) of Attachment C of the Agreement will be amended as shown in Exhibit B and Exhibit C of this Change Order.

4. The final adjustment to the Louisiana Sales and Use Tax Provisional Sum, Performance and Attendance Bonus Provisional Sum, and Insurance Provisional Sum will be made in accordance with Schedule EE-2 of Attachment EE of the Agreement.

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)	$	(16,842,054)
3.	The Contract Price Applicable to Subproject 6(a) prior to this Change Order was..................................	$	2,000,050,519
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 increased by this Change Order in the amount of..	$	17,944,000
6.	The Contract Price Applicable to Subproject 6(a) including this Change Order will be..................	$	2,017,944,519

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)	$	8,094,713
9.	The Contract Price Applicable to Subproject 6(b) prior to this Change Order was.................................	$	465,790,713
10.	The Contract Price Applicable to Subproject 6(b) will be unchanged by this Change Order..................	$	—
11.	The Provisional Sum Applicable to Subproject 6(b) will be decreased by this Change Order................	$	(17,944,000)
12.	The Contract Price Applicable to Subproject 6(b) including this Change Order will be..................	$	447,846,713

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)...	$	2,465,841,232
15.	The Contract Price will be unchanged by this Change Order in the amount of (add lines 4, 5, 10 and 11)	$	—
16.	The new Contract Price including this Change Order will be (add lines 14 and 15)...............................	$	2,465,841,232

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): Yes; see Exhibit B

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/ MDR 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/ Maurissa D. Rogers
Owner	Contractor
David Craft	Maurissa D. Rogers
Name	Name
SVP E&C	Sr Project Mgr, PVP
Title	Title
October 9, 2020	October 2, 2020
Date of Signing	Date of Signing

CHANGE ORDER

COVID-19 Impacts

PROJECT NAME: Sabine Pass LNG Stage 4 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00032

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: October 02, 2020

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. Pursuant to Article 6.2 of the Agreement (*Change Orders Requested by Contractor*), Parties agree this Change Order includes Contractor's actual costs incurred from March 2020 through July 2020 and forecasted costs from August 2020 through December 2020, both in response to the novel coronavirus (COVID-19) outbreak event.

   This Change Order is based on the following assumptions and qualifications through the end of December 2020:

   i. Contractor's Houston home office personnel have worked and shall continue working effectively remotely until such time the office is safe to re-open according to federal, state and local government officials' orders and Bechtel policies.

   ii. Contractor has been able to keep the Jobsite open throughout the event and shall continue doing so, to the extent reasonably possible, to advance the Work at the current rate of progress (or better if possible), with no planned shutdown in 2020.

   iii. Contractor shall continue to put forth diligent mitigation efforts to minimize impacts caused by the event to the extent reasonably practical, including but not limited to: increased craft professional hours for additional cleaning, disinfecting, etc.; increased bussing services to support social distancing; additional cleaning stations, waste management services, etc.; quarantine requirements for supplier technical support (international and others); continued COVID-19 testing costs and hours (excluding quarantine time); increased professional staff for contact tracing efforts; and additional safety PPE, communication materials (e.g., posters, signs, etc.).

   iv. No major COVID-19 infection outbreak on the Jobsite resulting in: (i) Site shutdown of all or critical scopes of the Work; or (ii) absenteeism at or above the twenty percent (20%) level for a sustained duration of more than four (4) Weeks. Should either of these triggers occur, the Parties shall jointly collaborate on mitigation actions and plans for shutdown accordingly.

   v. Existing government (local, state and/or federal) guidelines, executive orders, actions or directives as of 31 July 2020 shall remain unchanged through the end of December 2020. New government orders shall be subject to separate notices and Change Orders, if applicable.

   vi. Owner's operations and other professional staff personnel shall continue to support the Contractor's activities for the Project in support of the Work.

   vii. Subcontractors and Suppliers shall continue to provide uninterrupted support for construction activities either at Site or remotely if possible.

   viii. Any changes in the above assumptions and qualifications and additional costs beyond 2020 are excluded from this Change Order; and may be part of a separate Change Order in accordance with Article 6.2 of the Agreement.

2. Contractor has not experienced schedule impacts on the critical path of the CPM Schedule through 31 July 2020; and should all the qualifications and assumptions above remain as stated, Contractor does not anticipate any schedule impacts to the Project on the critical path of the CPM Schedule through the end of December 2020. In the event of the occurrence of any impacts to the critical path of the CPM Schedule, Contractor shall notify Owner in accordance with Article 6.5 of the Agreement.

3. The detailed cost breakdown of this Change Order is provided 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))	$	1,101,946
3.	The Contract Price Applicable to Subproject 6(a) prior to this Change Order was..................................	$	2,017,994,519
4.	The Contract Price Applicable to Subproject 6(a) will be increased by this Change Order in the amount of..	$	4,685,404
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..................	$	2,022,679,923

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)	$	(9,849,287)
9.	The Contract Price Applicable to Subproject 6(b) prior to this Change Order was.................................	$	447,846,713
10.	The Contract Price Applicable to Subproject 6(b) will be unchanged by this Change Order	$	—
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	$	447,846,713

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)..	$	2,465,841,232
15.	The Contract Price will be increased by this Change Order in the amount of (add lines 4, 5, 10 and 11)	$	4,685,404
16.	The new Contract Price including this Change Order will be (add lines 14 and 15)...............................	$	2,470,526,636

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): Yes; see Exhibit B of this Change Order

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): N/A

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/ MDR 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/ Maurissa D. Rogers
Owner	Contractor
David Craft	Maurissa D. Rogers
Name	Name
SVP E&C	Sr Project Mgr, PVP
Title	Title
October 9, 2020	October 2, 2020
Date of Signing	Date of Signing

CHANGE ORDER

Third Berth — Jetty Building (00A-4041) — Clean Agent System

PROJECT NAME: Sabine Pass LNG Stage 4 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00033

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: November 2, 2020

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 engineering, procurement and construction services to install the clean agent system in the Jetty Building (00A-4041).

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)	$	5,787,350
3.	The Contract Price Applicable to Subproject 6(a) prior to this Change Order was..................................	$	2,022,679,923
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..................	$	2,022,679,923

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)	$	(9,849,287)
9.	The Contract Price Applicable to Subproject 6(b) prior to this Change Order was.................................	$	447,846,713
10.	The Contract Price Applicable to Subproject 6(b) will be increased by this Change Order..................	$	115,915
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..................	$	447,962,628

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)...	$	2,470,526,636
15.	The Contract Price will be increased by this Change Order in the amount of (add lines 4, 5, 10 and 11)	$	115,915
16.	The new Contract Price including this Change Order will be (add lines 14 and 15)...............................	$	2,470,642,551

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/ KM 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/ Kane McIntosh
Owner	Contractor
David Craft	Kane McIntosh
Name	Name
SVP E&C	Sr Project Mgr
Title	Title
November 18, 2020	November 3, 2020
Date of Signing	Date of Signing

CHANGE ORDER

Vanessa Spare Valves

PROJECT NAME: Sabine Pass LNG Stage 4 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00034

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: November 18, 2020

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 procurement and delivery costs of twenty-four (24) Vanessa spare valves to Owner's warehouse.

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)	$	5,787,350
3.	The Contract Price Applicable to Subproject 6(a) prior to this Change Order was..................................	$	2,022,679,923
4.	The Contract Price Applicable to Subproject 6(a) will be increased by this Change Order in the amount of..	$	1,512,435
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..................	$	2,024,192,358

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)	$	(9,733,372)
9.	The Contract Price Applicable to Subproject 6(b) prior to this Change Order was.................................	$	447,962,628
10.	The Contract Price Applicable to Subproject 6(b) will be unchanged by this Change Order..................	$	—
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..................	$	447,962,628

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)...	$	2,470,642,551
15.	The Contract Price will be increased by this Change Order in the amount of (add lines 4, 5, 10 and 11)	$	1,512,435
16.	The new Contract Price including this Change Order will be (add lines 14 and 15)...............................	$	2,472,154,986

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): **Yes; see Exhibit B**

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): N/A

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/ KM 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/ Kane McIntosh
Owner	Contractor
David Craft	Kane McIntosh
Name	Name
SVP E&C	Sr Project Mgr
Title	Title
November 19, 2020	November 18, 2020
Date of Signing	Date of Signing

Exhibit 10.47

Sabine Pass Liquefaction, LLC

February 23, 2021

Cheniere Marketing International LLP
3rd Floor, The Zig Zag Building
70 Victoria Street
London SW1E 6SQ, United Kingdom
Attn: Commercial Operations

Re: Letter Agreement regarding the Base SPA ("**Letter Agreement**")

Dear Sir or Madam:

The Parties have entered into that certain Amended and Restated LNG Sale and Purchase Agreement (FOB) dated August 5, 2014 between Sabine Pass Liquefaction, LLC and Cheniere Marketing International LLP (as assignee of Cheniere Marketing, LLC) (as amended and assigned, the "**Base SPA**"). Capitalized terms used but not defined herein shall have the meanings given them in the Base SPA. This Letter Agreement sets forth the terms of certain sales and purchases of LNG under the Base SPA.

The Parties hereby agree that, notwithstanding Section 9.2 and subject to Section 14 of the Base SPA, the FPC (expressed in USD per MMBtu) applicable to the following number of cargoes shall equal USD one decimal seventy-two per MMBtu (US$1.72/MMBtu):

(a) up to three (3) cargoes scheduled for delivery in the 2021 Contract Year;

(b) up to five (5) or six (6) cargoes scheduled for delivery in each of the 2022, 2023, 2024 and 2025 Contract Years, such number to be nominated by Buyer for each such Contract Year during the ADP process for the relevant Contract Year; and

(c) up to three (3) or four (4) cargoes scheduled for delivery in the 2026 Contract Year, such number to be nominated by Buyer during the ADP process for the 2026 Contract Year.

Please indicate Buyer's agreement with the terms of this Letter Agreement by executing a copy of this Letter Agreement where indicated below and returning it to Seller.

Sincerely,

Sabine Pass Liquefaction, LLC

/s/
By: Zach Davis
Zach
Davis
Chief
Financial Officer

Accepted and Agreed:

Cheniere Marketing International LLP
acting by its managing member, Cheniere Marketing, LLC

By: /s/ Anatol Feygin
Anatol Feygin
Executive Vice President and Chief Commercial Officer

Exhibit 21.1

Subsidiaries of the Registrant as of December 31, 2020

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 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Cheniere Energy, Partners GP, LLC:

We consent to the incorporation by reference in the registration statement (No. 333-151155) on Form S-8 and the registration statements (Nos. 333-220017 and 333-219268) on Form S-3 of Cheniere Energy Partners, L.P. of our reports dated February 23, 2021, with respect to the consolidated balance sheets of Cheniere Energy Partners, L.P. as of December 31, 2020 and 2019, and the related consolidated statements of income, partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes and financial statement schedule I (collectively, the consolidated financial statements), and the effectiveness of internal control over financial reporting as of December 31, 2020, which reports appear in the December 31, 2020 annual report on Form 10-K of Cheniere Energy Partners, L.P.

Our report refers to a change in the method of accounting for leases.

/s/ KPMG LLP
KPMG LLP

Houston, Texas
February 23, 2021

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 23, 2021

/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 23, 2021

/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, 2020, 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 23, 2021

/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, 2020, 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 23, 2021

/s/ Zach Davis

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