CHENIERE

ENERGY PARTNERS, L.P.

2019 ANNUAL REPORT

2019 ACHIEVEMENTS AT A GLANCE

EXECUTION

Train 5 Placed Into Service

SABINE PASS LIQUEFACTION

Train 5 Completed, Date of First Commercial Delivery Achieved

Train 6 Full Notice to Proceed

~9 Months Ahead of Schedule

COMPLETED ON-TIME, ON-BUDGET, AND SAFELY

MAINTENANCE TURNAROUNDS

Two major turnarounds at Sabine Pass - over 500,000 manhours

GROWTH

Final Investment Decision Sabine Pass Train 6

HIGHLIGHTS

REVENUES	ADJUSTED EBITDA[1]	CARGOES EXPORTED
$6.8 BILLION	**$2.5 BILLION**	**>335**

NET INCOME	DISTRIBUTION PER UNIT	TBTU EXPORTED
$1.2 BILLION	**$2.46**	**~1,200** (~23 Million Tonnes)

UNITHOLDER LETTER

Dear Unitholders,

2019 was another extraordinary year for Cheniere Partners, one in which we accomplished significant objectives and reached milestones across all major aspects of our business.

We continued our unprecedented track record for excellence in execution.

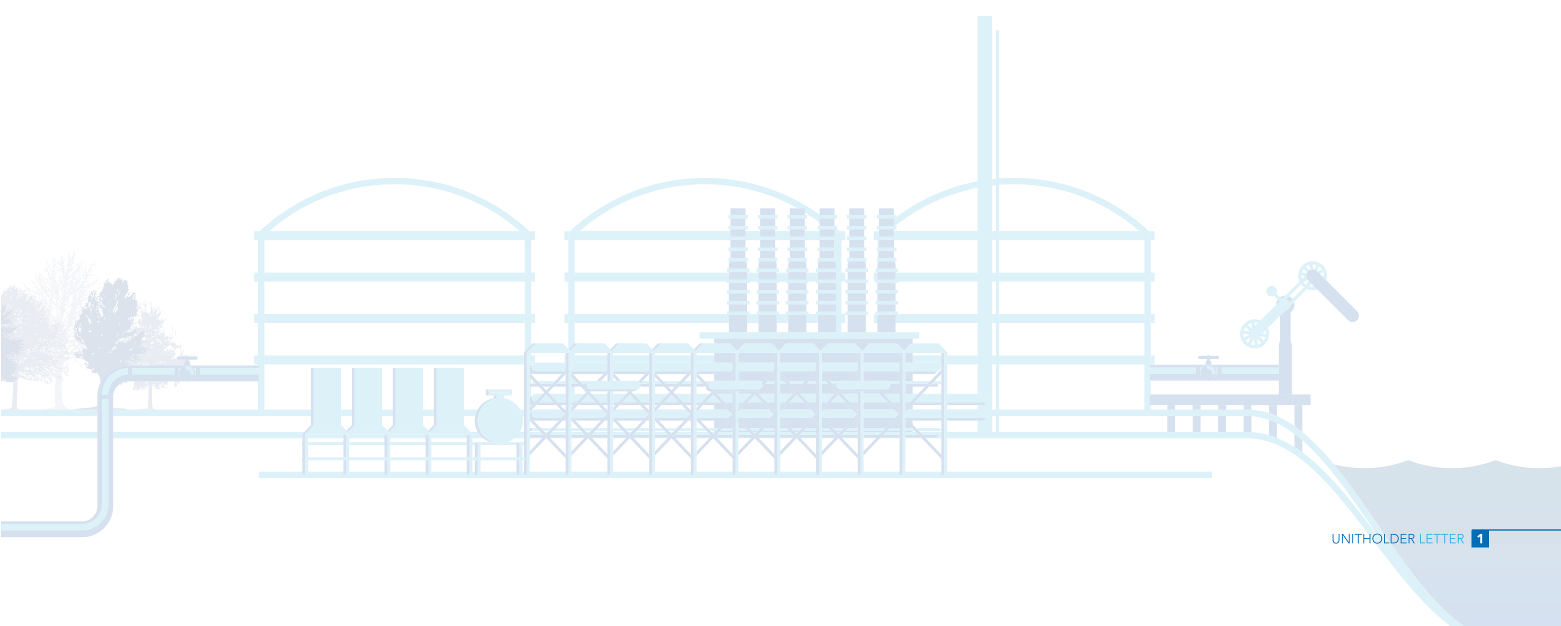
Alongside our EPC partner Bechtel, we completed Train 5 at Sabine Pass and placed it into service safely, within budget, and approximately nine months ahead of schedule. This achievement is a product of years of development, the hard work of thousands of dedicated professionals, and the relentless focus we have on execution through all phases of our projects. All five of our operating Trains have been completed ahead of schedule, resulting in over 170 additional cargoes of LNG produced, which has provided a significant economic benefit to Cheniere Partners, our customers, and our stakeholders.

>6%
of Total Global
LNG Supply

We are laser focused on maintaining excellence in execution as Sabine Pass Train 6 progresses through construction. Train 6 is progressing on an accelerated timeline and remains on schedule to be completed in the first half of 2023.

We produced and exported over 335 cargoes of LNG totaling approximately 1,200 TBtu, or almost 23 million tonnes, during 2019. We produced over 6% of global LNG supply, which totaled over 360 million tonnes in 2019. In the fourth quarter, we produced and exported a record 95 cargoes, over a cargo per day on average, from Sabine Pass.

We also exhibited operational excellence in our first major maintenance turnarounds at Sabine Pass. The turnarounds involved over 500 thousand manhours and were accomplished ahead of schedule, on budget, and, most importantly, with no safety incidents.



We responsibly deliver a reliable, competitive, and integrated source of LNG in a safe and rewarding work environment.

2 Long-Term LNG Customers On-Boarded in 2019

TOTAL

centrica

We prioritized customer relationships and delivered on our promises to our customers.

We continued our perfect track record of delivering every scheduled cargo of LNG to our customers in 2019. We remain committed to setting the standard by which LNG operators globally will be measured.

We on-boarded two long-term LNG customers in 2019 when we achieved the date of first commercial delivery under our 20-year LNG Sale and Purchase Agreements (SPAs) with Centrica plc and Total Gas & Power North America, Inc. relating to Sabine Pass Train 5 in September. Through year-end 2019, we had on-boarded six of our long-term, creditworthy counterparties.

We moved forward with our sixth liquefaction Train and increased our run-rate production and distributable cash flow guidance.

We locked in liquefaction capacity growth when we made a positive Final Investment Decision on Sabine Pass Train 6 in May and issued Bechtel full Notice to Proceed with the project in early June. Bechtel has made significant progress on engineering, procurement, and construction efforts for Train 6, which had a project completion percentage of 43.7% as of year-end 2019.

We identified opportunities to increase run-rate production per Train through production optimization, maintenance optimization, and debottlenecking projects at Sabine Pass. As

Sabine Pass

Train 6

Final Investment Decision

Sabine Pass Train 6 in foreground, January 2020

a result, we increased our run-rate production to 4.8-4.9 million tonnes per annum (mtpa) per Train, up from 4.5-4.9 mtpa per Train.

Incorporating the impact of Sabine Pass Train 6 and increased run-rate production guidance, we also increased our run-rate distributable cash flow per unit guidance to $3.70-$3.90 annually, up from $3.30-$3.60 annually.

We overcame market headwinds to produce record financial results.

Significant LNG supply growth, warmer than normal weather in LNG consuming markets, and global trade concerns led to decreased short-term pricing of LNG as the year progressed. The global market grew by approximately 40 million tonnes, or over 12%, to approximately 360 million tonnes in 2019, a growth level on par with the industry's previous largest single-year growth which occurred in 2010. We managed unsold capacity effectively during the year, including excess volumes available due to the early completion of Sabine Pass Train 5. The effectiveness of these short-term sales, alongside higher-than-expected production from our Trains, enabled us to achieve financial results within our guidance range for the year despite short-term market headwinds.

We reported net income of approximately $1.2 billion and Adjusted EBITDA(1) of $2.5 billion for 2019. We declared and paid distributions of $2.46 per unit to common unitholders for full year 2019, an increase of approximately 8% as compared to distributions per unit for full year 2018.

Our common units had a total return of 17% in 2019.

We exhibited discipline in balance sheet management through a series of capital market transactions.

We financed approximately 45% of the cost of Sabine Pass Train 6 and supporting infrastructure at Cheniere Partners, initially through $1.5 billion senior secured credit facilities. We later refinanced this with the issuance of $1.5 billion 4.5% Senior Notes due 2029. Financing less than half of the cost of Sabine Pass Train 6 with debt enables us to simultaneously grow and de-lever the company, and issuing debt at the Cheniere Partners level further improves the investment grade credit metrics of Sabine Pass Liquefaction.

A leading global enabler of the transition to a sustainable, lower carbon future

We are playing an integral role in the global transition to cleaner energy.

Cheniere Partners is an energy infrastructure company which operates in a responsible, environmentally conscious manner, and our LNG is a growing part of the global energy transition to cleaner burning natural gas.

One of the most impactful ways greenhouse gas emissions can be reduced worldwide is through coal-to-gas switching, especially in large emerging market nations where small percentage changes in energy consumption can make a significant difference in total carbon emissions. As one of the largest operators of liquefaction capacity worldwide, Cheniere Partners is a leading global enabler of the transition to a sustainable, lower carbon future.

Our vision is to provide clean, secure, and affordable LNG to the world

We believe the future for Cheniere Partners is secure and stable.

As we look to the future, the fundamentals of our business remain extremely strong. From 2016 through 2019, the global LNG market grew by approximately 100 million tonnes, and it is forecast to grow another approximately 200 million tonnes by 2030. The LNG market is dynamic, undergoing significant growth and evolution, and we are ideally positioned to leverage our competitive advantages – our world-class platform, excellence in operations and execution, and highly-contracted production base – to continue to generate significant stable, fixed fee cash flow and to manage volatility that may appear in the short-term market from time to time.

I thank you all for your continued support of Cheniere Partners.

Sincerely,

Jack A. Fusco
Chairman, President and CEO

(1) Adjusted EBITDA is a non-GAAP measure. A reconciliation to Net income, the most comparable U.S. GAAP measure, is included in the appendix.

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, 2019

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 is a shell company (as defined in Rule 12b-2 of the Act). Yes†☐† No ☒

The aggregate market value of the registrant's common units held by non-affiliates of the registrant was approximately $10.3 billion as of June 28, 2019.

As of February 19, 2020, the registrant had 348,631,292 common units and 135,383,831 subordinated units outstanding.

Documents incorporated by reference: **None**

CHENIERE ENERGY PARTNERS, L.P.

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DEFINITIONS

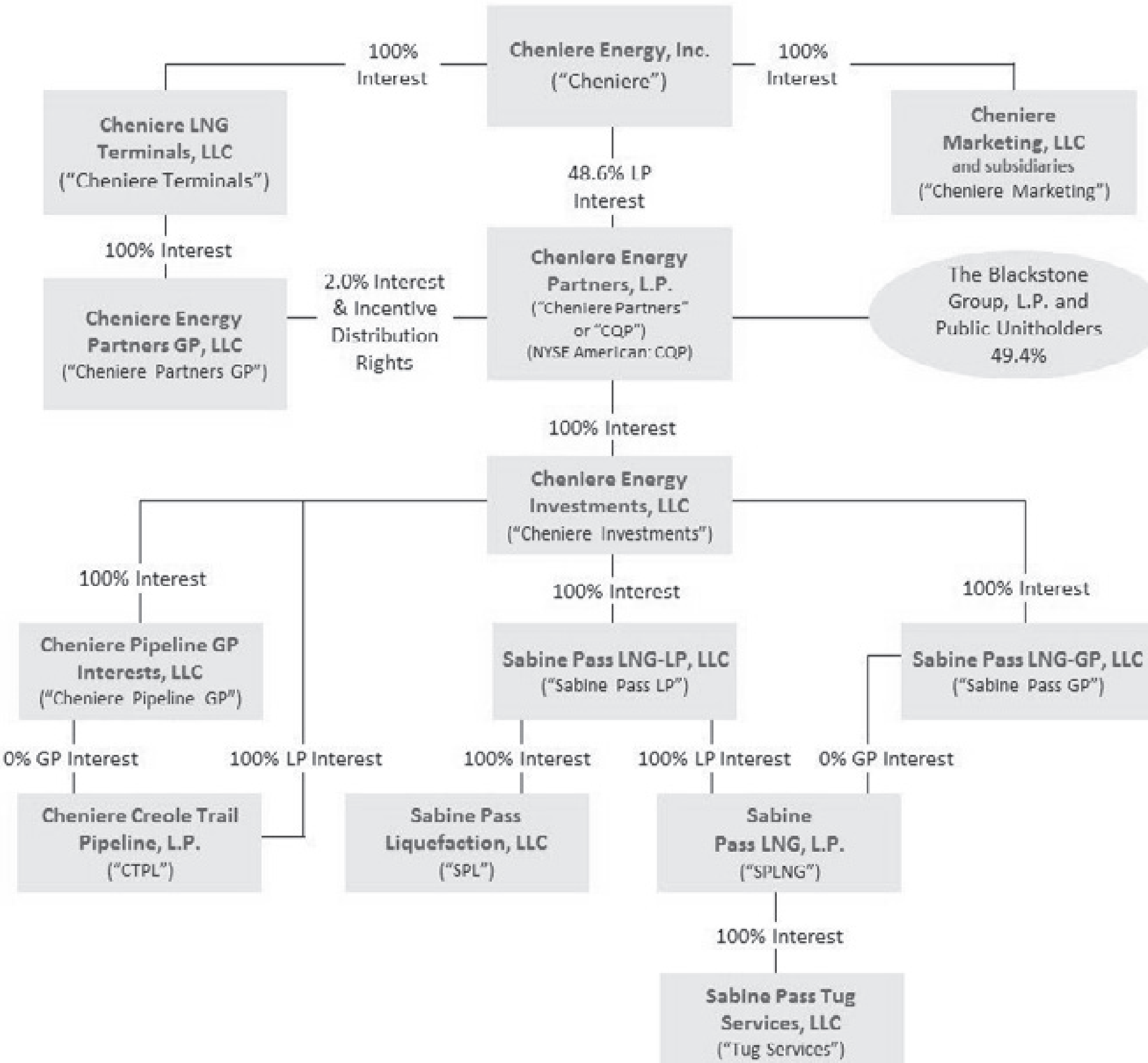
As used in this annual report, the terms listed below have the following meanings:

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, 2019, 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.

References to "Blackstone Group" refer to The Blackstone Group, L.P. References to "Blackstone CQP Holdco" refer to Blackstone CQP Holdco LP. References to "Blackstone" refer to Blackstone Group and Blackstone CQP Holdco.

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; and
- any other statements that relate to non-historical or future information.

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

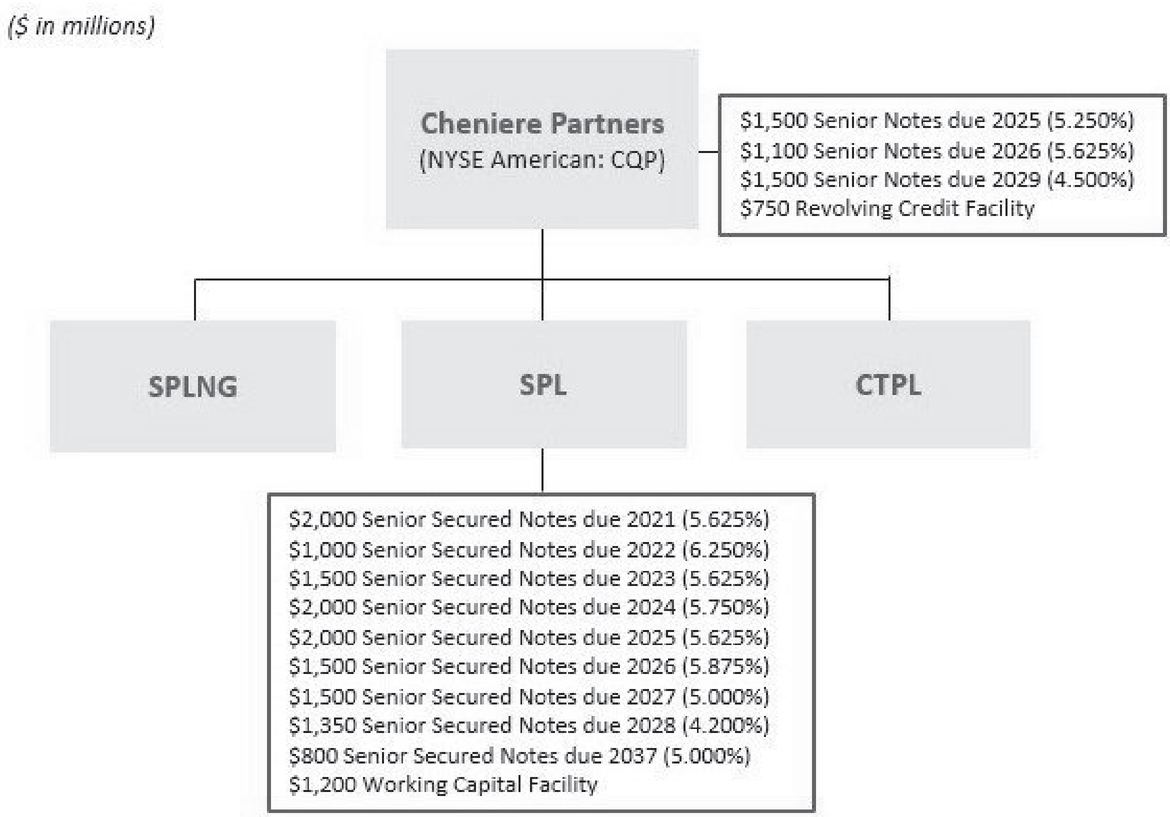
General

We are a publicly traded Delaware limited partnership formed by Cheniere Energy, Inc. (“Cheniere”) 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, Sabine Pass Liquefaction, LLC (“SPL”), we are currently operating five natural gas liquefaction Trains and are constructing one additional Train 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 marine berths 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. We hold a significant land position at the Sabine Pass LNG terminal, which provides opportunity for further liquefaction capacity expansion. Further development of the Sabine Pass LNG terminal 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, 2019:



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 six of eight long-term SPA customers as of December 31, 2019;
- safely, on-time and on-budget completing construction and commencing operation of Train 6 of the Liquefaction Project; and
- maximizing the production of LNG to serve our long-term customers and generating steady and stable revenues and operating cash flows;

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. We have received authorization from the FERC to site, construct and operate Trains 1 through 6. 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, 2019:

	Train 6
Overall project completion percentage	43.7%
Completion percentage of:	
Engineering	91.5%
Procurement	60.9%
Subcontract work	37.4%
Construction	9.7%
Date of expected substantial completion	1H 2023

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 for a 30-year term, which commenced in May 2016, and non-FTA countries for a 20-year term, which commenced in June 2016, 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 for a 25-year term and non-FTA countries for a 20-year term, both of which commenced in December 2018, 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 for a 20-year term, which partially commenced in June 2019 and the remainder commenced in September 2019, in an amount up to a combined total of 503.3 Bcf/yr of natural gas (approximately 10 mtpa).

In each case, the terms of these authorizations began on the earlier of the date of first export thereunder or the date specified in the particular order. In addition, SPL received an order providing for a three-year makeup period with respect to each of the non-FTA orders for LNG volumes SPL was authorized but unable to export during any portion of the initial 20-year export period of such order.

The DOE issued orders authorizing SPL to export domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing January 2020, in an aggregate amount up to the equivalent of 600 Bcf of natural gas (however, exports under this order, when combined with exports under the orders above, may not exceed 1,509 Bcf/yr).

An application was filed in September 2019 to authorize 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 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. The application is currently pending before DOE.

Customers

SPL has entered into fixed price long-term SPAs generally with terms of 20 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. Under these SPAs, the customers will purchase LNG from SPL on a free on board ("FOB") basis for a price consisting of a fixed fee per MMBtu of LNG (a portion of which is subject to annual adjustment for inflation) plus a variable fee per MMBtu of LNG 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 by the end of 2020, 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 43 cargoes scheduled for delivery in 2020 at a price of 115% of Henry Hub plus $1.67 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 by the end of 2020.

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,		
	2019	2018	2017
BG	27%	28%	39%
Naturgy	18%	21%	27%
KOGAS	19%	23%	23%
GAIL	20%	19%	—%

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, 2019, SPL had secured up to approximately 3,850 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 an optional third marine berth. As of December 31, 2019, we have incurred $1.1 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, 2019, 2018 and 2017, SPL recorded $104 million, $30 million and $23 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.

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 bi-directional natural gas flow on the Creole Trail Pipeline system to allow for the delivery of up to 1,530,000 Dekatherms per day of feed gas to the Sabine Pass LNG terminal. In November 2013, CTPL received approval from the Louisiana Department of Environmental Quality ("LDEQ") for the proposed modifications and, 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 each terminal from currently authorized levels to an amount which reflects more accurately the capacity of each 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 U.S. 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 License

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, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea and Singapore. 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 Services, U.S. Department of the Interior, U.S. Fish and Wildlife Service, the U.S. Environmental Protection Agency (the "EPA"), U.S. Department of Homeland Security and the Louisiana Department of Environmental Quality ("LDEQ").

The USACE issues its permits under the authority of the Clean Water Act (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 that market. The regulatory regime created by the Dodd-Frank Act is designed primarily to (1) regulate certain participants in the swaps markets, including entities falling within the categories of "Swap Dealer" and "Major Swap Participant," (2) require clearing and exchange trading of standardized swaps of certain classes as designated by the CFTC, (3) increase swap market transparency through robust reporting and recordkeeping requirements, (4) reduce financial risks in the derivatives market by imposing margin or collateral requirements on both cleared and, in certain cases, uncleared swaps, (5) provide the CFTC with expanded authority to establish position limits on certain physical commodity futures and options contracts and their economically equivalent swaps as it finds necessary and appropriate and (6) otherwise enhance the rulemaking and enforcement authority of the CFTC and the SEC regarding the derivatives markets. Most of the regulations are already in effect, while other rules and regulations, including the proposed margin rules, position limits and commodity clearing requirements, remain to be finalized or effectuated. Therefore, the impact of those rules and regulations on our business continues to be uncertain.

A provision of the Dodd-Frank Act requires the CFTC, in order to diminish or prevent excessive speculation in commodity markets, to adopt rules, as it finds necessary and appropriate, imposing new position limits on certain physical commodity futures contracts and options thereon, as well as economically equivalent swaps traded on registered swap trading platforms and on over-the-counter swaps that perform a significant price discovery function with respect to certain markets. In that regard, the CFTC has re-proposed position limits rules that would modify and expand the applicability of limits on speculative positions in certain physical commodity futures contracts and economically equivalent futures, options and swaps for or linked to certain physical commodities, including Henry Hub natural gas, that market participants may hold, subject to limited exemptions for certain bona fide hedging and other types of transactions. It is uncertain at this time whether, when and in what form the CFTC's proposed new position limits rules may become final and effective.

Pursuant to rules adopted by the CFTC, certain interest rate swaps and index credit default swaps must be cleared through a derivatives clearing organization and executed on an exchange or swap execution facility. The CFTC has not yet proposed to designate swaps in any other asset classes, including swaps relating to physical commodities, for mandatory clearing and trade execution, but could do so in the future. Although we expect to qualify for the end-user exception from the mandatory clearing and exchange-trading requirements applicable to any swaps that we enter into to hedge our commercial risks, the mandatory clearing and exchange-trading requirements may apply to other market participants, including our counterparties (who may be registered as Swap Dealers), with respect to other swaps, and the application of such rules may change the market cost and general availability in the market of swaps of the type we enter into to hedge our commercial risks and, thus, the cost and availability of the swaps that we use for hedging.

As required by provisions of the Dodd-Frank Act, the CFTC and federal banking regulators have adopted rules to require Swap Dealers and Major Swap Participants, 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 expect to qualify as such a non-financial-entity end user with respect to the swaps that we enter into to hedge our commercial risks.

Any new rules or changes to existing rules promulgated under the Dodd-Frank Act could (1) impair the availability of derivatives, (2) materially increase the cost of, or decrease the liquidity of, the derivatives we use to hedge, (3) significantly alter the terms and conditions of derivatives and (4) potentially increase our exposure to less creditworthy counterparties. Further, any resulting reduction in the use of derivatives could make cash flow more volatile and less predictable, which in turn could adversely affect our ability to plan for and fund capital expenditures.

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 have largely been stayed or repealed including by amendments adopted by the EPA on February 23, 2018, additional proposed amendments to new source performance standards for the oil and gas industry on September 24, 2019, and the EPA's June 19, 2019 adoption of the Affordable Clean Energy rule for power generation.

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 ("CWA")

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), and in Texas, by the Texas Commission on Environmental Quality.

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 U.S. Fish and Wildlife Service (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. The revisions are intended to streamline these processes and create more flexibility for the FWS when making ESA-related decisions.

In addition, in December 2017, the Department of Interior's ("DOI's") Solicitor's Office issued an official opinion that the MBTA's broad prohibition on "taking" migratory birds applies only to affirmative actions and does prohibit incidental harm. In April 2018, the FWS issued guidance consistent with the DOI's opinion and on January 30, 2020, the FWS issued a proposed rule defining the scope of the MBTA to cover only actions directed at migratory birds, their nests or their eggs.

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 these recent 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 constructing 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) 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. Global demand for natural gas is projected by the International Energy Agency to grow by approximately 27 trillion cubic feet ("Tcf") between 2018 and 2030 and 39 Tcf between 2018 and 2035. LNG's share is seen growing from about 11% in 2018 to about 16% of the global gas market in 2030 and 18% in 2035. Wood Mackenzie Limited ("WoodMac") forecasts that global demand for LNG will increase by approximately 79%, from approximately 316 mtpa, or 15.2 Tcf, in 2018, to approximately 566 mtpa, or 27.2 Tcf, in 2030 and to 678 mtpa or 32.6 Tcf in 2035. WoodMac also forecasts LNG production from existing operational facilities and new facilities already under construction will be able to supply the market with approximately 469 mtpa in 2030, declining to 430 mtpa in 2035. This will result in a market need for construction of an additional approximately 97 mtpa of LNG production by 2030 and about 248 mtpa by 2035. 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. As of January 31, 2020, 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, 2020, Cheniere and its subsidiaries had 1,530 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.

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

- Risks Relating to Our Financial Matters;
- Risks Relating to Our Business;
- Risks Relating to Our Cash Distributions;
- Risks Relating to an Investment in Us and Our Common Units; and
- Risks Relating to Tax Matters.

Risks Relating to Our Financial Matters

Our existing level of cash resources and significant debt could cause us to have inadequate liquidity and could materially and adversely affect our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

As of December 31, 2019, we had $1.8 billion cash and cash equivalents, $0.2 billion of current restricted cash and $17.8 billion of total debt outstanding on a consolidated basis (before unamortized premium, discount and debt issuance costs), excluding $414 million aggregate outstanding letters of credit. We incur, and will incur, significant interest expense relating to the assets at the Sabine Pass LNG terminal and we anticipate needing to incur additional debt to finance the construction of Train 6 of the Liquefaction Project. 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 may sell equity or equity-related securities, including additional common units. Such sales could dilute our unitholders' proportionate indirect interests in our assets, business operations, Liquefaction Project and other projects, and could adversely affect the market price of our common units.

We have 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 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, 2019, 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. If any 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 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 the price, volume and timing risk associated with the purchase of natural gas, we use futures, swaps and option contracts traded or cleared on the Intercontinental Exchange and the New York Mercantile Exchange or over-the-counter options and swaps with other natural gas merchants and financial institutions. Hedging arrangements could expose us to risk of financial loss in some circumstances, including when:

- expected supply is less than the amount hedged;
- 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.

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 and to be 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.

The CFTC has re-proposed position limits rules that would modify and expand the applicability of position limits on the amounts of certain speculative futures contracts, as well as economically equivalent options, futures and swaps for or linked to certain physical commodities, including Henry Hub natural gas, that market participants may hold, subject to limited exemptions for certain bona fide hedging positions and other types of transactions. To the extent the revised CFTC position limits proposal becomes final, our ability to execute our hedging strategies described above could be limited. It is uncertain at this time whether, when and in what form the CFTC's proposed new position limits rules may become final and effective.

Under the Dodd-Frank Act and the rules adopted thereunder, certain swaps may be required to be cleared through a derivatives clearing organization. While the CFTC has designated certain interest rate swaps and index credit default swaps for mandatory clearing, it has not yet finalized rules designating any physical commodity swaps, for mandatory clearing or mandatory exchange trading. Further, we qualify for the end-user exception from the mandatory clearing and trade execution requirements for our swaps entered into to hedge our commercial risks. If we fail to qualify for that exception as to any swap we enter into and have to clear that swap through a derivatives clearing organization, we could be required to post margin (or post higher margin than if we entered into an uncleared OTC swap) with respect to such swap, our cost of entering into and maintaining such swap could increase and we would not enjoy the same flexibility with the cleared swaps that we enjoy with the uncleared OTC swaps we enter into. Moreover, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the market cost and general availability in the market of swaps of the type we enter into to hedge our commercial risks and, thus, the cost and availability of the swaps that we use for hedging.

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.

The Dodd-Frank Act also imposes other regulatory requirements on swaps market participants, including end users of swaps, such as regulations relating to swap documentation, reporting and recordkeeping, and certain business conduct rules applicable to swap dealers and major swap participants. Together with the Basel III capital requirements on certain swaps market participants, the regulatory requirements of the Dodd-Frank Act and the rules thereunder relating to swaps and derivatives market participants could significantly increase the cost of derivative contracts (including through requirements to post margin or collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against certain risks that we encounter and reduce our ability to monetize or restructure our existing derivative contracts and to execute our hedging strategies. If, as a result of the swaps regulatory regime discussed above, we were to reduce our use of swaps to hedge our risks, such as commodity price risks that we encounter in our operations, our operating results and cash flows may become more volatile and could be otherwise adversely affected.

We expect that our hedging activities will remain subject to significant and developing regulations and regulatory oversight. However, the full impact of the various U.S. (and non-U.S.) regulatory developments in connection with these activities will not be known with certainty until such derivatives market regulations are fully implemented and related market practices and structures are fully developed.

Risks Relating to Our Business

Operation of the Sabine Pass LNG terminal, the Liquefaction Project, the Creole Trail Pipeline and other facilities that we may construct involves significant risks.

As more fully discussed in these Risk Factors, the Sabine Pass LNG terminal, the Liquefaction Project, the Creole Trail Pipeline and other facilities that we may construct face operational risks, including the following:

- the facilities' performing below expected levels of efficiency;

- breakdown or failures of equipment;
- operational errors by vessel or tug operators;
- operational errors by us or any contracted facility operator;
- labor disputes; and
- weather-related interruptions of operations.

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 the 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 Bechtel 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.

Delays in the construction of one or more Trains beyond the estimated development periods, as well as change orders to the EPC contracts with Bechtel 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 and Hurricane Harvey in 2017 caused temporary suspension in construction of our Liquefaction Project or caused minor damage to our Liquefaction Project. 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, 2020, Cheniere and its subsidiaries had 1,530 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 or changes in applicable laws and regulations 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 43 cargoes scheduled for delivery in 2020 at a price of 115% of Henry Hub plus $1.67 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, 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 shortages of LNG vessels worldwide, 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, and the availability of the vessels could be delayed 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;
- political or economic disturbances in the countries where the vessels are being constructed;
- changes in governmental regulations or maritime self-regulatory organizations;
- work stoppages or other labor disturbances at the shipyards;
- bankruptcy or other financial crisis of shipbuilders;
- quality or engineering problems;
- weather interference or a catastrophic event, such as a major earthquake, tsunami or fire; and
- shortages of or delays in the receipt of necessary construction materials.

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 have largely been stayed or repealed including by amendments adopted by the EPA on February 23, 2018, additional proposed amendments to new source performance standards for the oil and gas industry on September 24, 2019, and the EPA's June 19, 2019 adoption of the Affordable Clean Energy rule for power generation. However, Congress or a future Administration may reverse these decisions. 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 terminal, or could increase compliance costs for our operations.

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 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 the applicable statues 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 2020 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, 2019, we paid aggregate distributions of $1.3 billion on our common units, subordinated units and related general partner units including IDRs.

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, 2019, we had $17.8 billion of total consolidated debt (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. $2.0 billion of our indebtedness will mature in 2021, $1.0 billion will mature in 2022, $1.5 billion will mature in 2023, $2.0 billion will mature in 2024, approximately $10.5 billion will mature between 2024 and 2029 and $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 and subordinated 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 and subordinated 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 and the ability of the subordinated units to convert to common units;
- 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 and subordinated 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 and subordinated units, but it is contractually prohibited from voting our units that it holds in favor of the removal of our general partner. If our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically be converted into common units and any existing arrearages on the common units will be extinguished. A removal of our general partner under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined in our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful misconduct in its capacity as our general partner. Cause does not include most cases of poor management of the business, so the removal of the general partner because of the unitholders' dissatisfaction with our general partner's performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

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.

At any time during the subordination period, with the approval of the conflicts committee of the board of directors of our general partner, we may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. After the subordination period, 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;
- because a lower percentage of total outstanding units will be subordinated units, the risk will increase that a shortfall in the payment of the initial quarterly distributions will be borne by our common unitholders;
- 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, 2019, the market price of our common units ranged between $26.41 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; 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 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 our subordinated 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, 2019, Cheniere owned 104,488,671 of our common units and 135,383,831 of our subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier. 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. From time to time the U.S. President and members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that would affect publicly traded partnerships or an investment in our common units, including elimination of partnership tax treatment for certain publicly traded partnerships.

Any changes to the U.S. federal income tax laws and interpretations thereof (including administrative guidance relating to the Tax Cuts and Jobs Act (the "TCJA")) 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.

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.

We intend to allocate items of income, gain, loss and deduction among the holders of our common units and subordinated units on or after the date that the subordination period ends to ensure that common units issued in exchange for our subordinated units have the same economic and federal income tax characteristics as our other common units. Any such allocation of items of our income or gain to unitholders, which may include allocations to holders of our common units, would not be accompanied by a distribution of cash to such unitholders. In addition, any such allocation of items of deduction or loss to specific unitholders (for example, to the holder of the subordinated units) would effectively reduce the amount of items of deduction or loss that will be allocated to other unitholders.

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.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the TCJA, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income plus 30% of our "adjusted taxable income." For the purposes of this limitation, adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion. However, proposed Treasury Regulations provide that depreciation, amortization, or depletion expense that is capitalized to inventory, is not treated as depreciation, amortization, or depletion deduction for purposes of computing adjusted taxable income. The finalization of the proposed Treasury Regulations, in their current form, would increase the likelihood that our interest will be subject to limitation. To the extent the business interest expense limitation applies, it could result in an increase in the taxable income allocable to a unitholder without any corresponding increase in the cash available for distribution to such unitholder.

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. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. 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, the transferee of an interest in a partnership that is engaged in a U.S. trade or business is generally required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee the amount that should have been withheld by the transferees but were not withheld. Recently issued proposed regulations provide, with respect to transfers of publicly traded interests sold through a broker, that the obligation to withhold is imposed on the transferor's broker and that a transferor's "amount realized" does not include its share of a publicly traded partnership's liabilities for purposes of determining the amount subject to withholding. Pending the issuance of final regulations, the IRS has temporarily suspended the application of the withholding requirements on transfers of publicly traded interests in publicly traded partnerships. It is not clear when the proposed regulations will be finalized or if they will be finalized in their current form.

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, 2020, we had 348.6 million common units outstanding held by 10 record owners.

We consider cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. 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. On August 2, 2017, the 45.3 million Class B units held by Cheniere Energy Partners LP Holdings, LLC and 100.0 million Class B units held by Blackstone CQP Holdco mandatorily converted into common units in accordance with the terms of our partnership agreement. Below is a description of our cash distribution policy regarding common and subordinated units. References therein to "unitholders" made in the context of the recipients of quarterly cash distributions refer to our common unitholders and subordinated unitholders.

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.

Subordination Period

During the subordination period, the common units will have the right to receive distributions of available cash from operating surplus in an amount equal to the initial quarterly distribution of $0.425 per quarter, plus any arrearages in the payment of the initial quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. Cheniere owns all of the 135.4 million subordinated units, representing 28.0% of the limited partner interests in us as of December 31, 2019. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until after the common units have received the initial quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordination period is to increase the likelihood that during this period there will be sufficient available cash to pay the initial quarterly distribution on the common units.

As a result of reduced available cash for distributions, we did not pay distributions on our subordinated units with respect to the quarter ended June 30, 2010 through the quarter ended June 30, 2017, but resumed making cash distributions with respect to the quarter ended September 30, 2017.

Definition of Subordination Period

The subordination period will extend until the first business day following the distribution of available cash to partners in respect of any quarter that each of the following occurs:

- distributions of available cash from operating surplus on each of the outstanding common units, subordinated units and any other outstanding units that are senior or equal in right of distribution to the subordinated units equaled or exceeded the sum of the initial quarterly distributions on all of the outstanding common units, subordinated units, general partner units and any other outstanding units that are senior or equal in right of distribution to the subordinated units for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- the "adjusted operating surplus" (as defined below) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the initial quarterly distributions on all of the outstanding common units, subordinated units, general partner units and any other outstanding units that are senior or equal in right of distribution to the subordinated units during those periods on a fully diluted basis; and
- there are no arrearages in payment of the initial quarterly distribution on the common units.

Expiration of the Subordination Period

When the subordination period expires, each outstanding subordinated unit will convert into one common unit and will then participate pro rata with the other common units in distributions of available cash. In addition, if the unitholders remove our general partner other than for cause and units held by the general partner and its affiliates are not voted in favor of such removal:

- the subordination period will end and each subordinated unit will immediately convert into one common unit;
- any existing arrearages in payment of the initial quarterly distribution on the common units will be extinguished; and
- the general partner will have the right to convert its general partner units and its IDRs into common units or to receive cash in exchange for those interests.

Early Conversion of Subordinated Units

The subordination period will automatically terminate and all of the subordinated units will convert into common units on a one-for-one basis on the first business day following the distribution of available cash to partners in respect of any quarter that each of the following occurs:

- in connection with distributions of available cash from operating surplus, the amount of such distributions constituting "contracted adjusted operating surplus" (as defined below) on each outstanding common unit, subordinated unit and any other outstanding unit that is senior or equal in right of distribution to the subordinated units equaled or exceeded $0.638 (150% of the initial quarterly distribution) for each quarter in the four-quarter period immediately preceding that date;
- the contracted adjusted operating surplus generated during each quarter in the four-quarter period immediately preceding that date equaled or exceeded the sum of a distribution of $0.638 (150% of the initial quarterly distribution) on all of the outstanding common units, subordinated units, general partner units, any other units that are senior or equal in right of distribution to the subordinated units, and any other equity securities that are junior to the subordinated units that the board of directors of our general partner deems to be appropriate for the calculation, after consultation with management of our general partner, on a fully diluted basis; and
- there are no arrearages in payment of the initial quarterly distribution on the common units

Definition of Adjusted Operating Surplus

We define adjusted operating surplus in our partnership agreement, and for any period, it generally means:

- operating surplus generated with respect to that period; less
- any net increase in working capital borrowings with respect to that period; less
- any net reduction in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; plus
- any net decrease in working capital borrowings with respect to that period; plus
- any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes the $30 million operating surplus "basket," net increases in working capital borrowings, net drawdowns of reserves of cash generated in prior periods.

Definition of Contracted Adjusted Operating Surplus

We define contracted adjusted operating surplus in our partnership agreement and it:

- generally means adjusted operating surplus derived solely from SPAs and TUAs, in each case, with a minimum term of three years with counterparties who are not affiliates of Cheniere; and

- excludes revenues and expenses attributable to the portion of payments made under the SPAs related to the final settlement price for the New York Mercantile Exchange's Henry Hub natural gas futures contract for the month in which the relevant cargo's delivery window is scheduled.

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,				
	2019	2018	2017	2016	2015
Consolidated Statement of Income Data:					
Revenues (including transactions with affiliates)	$ 6,838	$ 6,426	$ 4,304	$ 1,100	$ 270
Income from operations	2,040	1,979	1,156	250	3
Interest expense, net of capitalized interest	(885)	(733)	(614)	(357)	(185)
Net income (loss)	1,175	1,274	490	(171)	(319)
Common Unit Data:					
Net income (loss) per common unit	$ 2.25	$ 2.51	$ (1.32)	$ (0.20)	$ (0.43)
Weighted average units outstanding	348.6	348.6	178.5	57.1	57.1

	December 31,				
	2019	2018	2017	2016	2015
Consolidated Balance Sheet Data:					
Property, plant and equipment, net	$ 16,368	$ 15,390	$ 15,139	$ 14,158	$ 11,932
Total assets	19,384	17,974	17,533	15,542	12,833
Current debt, net	—	—	—	224	1,673
Long-term debt, net	17,579	16,066	16,046	14,209	10,018

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
- Liquidity and Capital Resources
- Contractual Obligations
- Results of Operations
- 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 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 marine berths 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, 2019 and through the filing date of this Form 10-K include the following:

Strategic

- In May 2019, the board of directors of our general partner made a positive final investment decision ("FID") with respect to Train 6 of the Liquefaction Project and issued a full notice to proceed with construction to Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") in June 2019.

Operational

- As of February 21, 2020, over 900 cumulative LNG cargoes totaling over 60 million tonnes of LNG have been produced, loaded and exported from the Liquefaction Project.
- In March 2019, SPL achieved substantial completion of Train 5 of the Liquefaction Project and commenced operating activities.

Financial

- In September 2019, we issued an aggregate principal amount of $1.5 billion of 4.500% Senior Notes due 2029 (the "2029 CQP Senior Notes") to prepay the outstanding balance under the $750 million term loan under our credit facilities (the "2019 CQP Credit Facilities"), which were entered into in May 2019, and for general corporate purposes, including funding future capital expenditures in connection with the construction of Train 6 at the Liquefaction Project. After applying the proceeds of the 2029 CQP Senior Notes, only a $750 million revolving credit facility, which is currently undrawn, remains as part of the 2019 CQP Credit Facilities.
- We reached the following contractual milestones:
    - In September 2019, the date of first commercial delivery was reached under the 20-year SPAs with Centrica plc and Total Gas & Power North America, Inc. ("Total") relating to Train 5 of the Liquefaction Project.
    - In March 2019, the date of first commercial delivery was reached under the 20-year SPA with BG Gulf Coast LNG, LLC relating to Train 4 of the Liquefaction Project.

Liquidity and Capital Resources

The following table provides a summary of our liquidity position at December 31, 2019 and 2018 (in millions):

	December 31,	
	2019	2018
Cash and cash equivalents	$ 1,781	$ —
Restricted cash designated for the following purposes:		
Liquefaction Project	181	756
Cash held by us and our guarantor subsidiaries	—	785
Available commitments under the following credit facilities:		
$1.2 billion SPL Working Capital Facility ("SPL Working Capital Facility")	786	775
2019 CQP Credit Facilities	750	—
$2.8 billion Credit Facilities ("2016 CQP Credit Facilities")	—	115

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 (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 customary 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, 2020 for the 2025 CQP Senior Notes, 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, 2020 for the 2025 CQP Senior Notes, 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 105.250% of the aggregate principal amount of the 2025 CQP Senior Notes, 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 on or after October 1, 2020 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.

2016 CQP Credit Facilities

In May 2019, the remaining commitments under the 2016 CQP Credit Facilities were terminated.

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.

Loans under the 2019 CQP Credit Facilities accrue interest at a variable rate per annum equal to LIBOR or the base rate (equal to the highest of the prime rate, the federal funds effective rate, as published by the Federal Reserve Bank of New York, plus 0.50%, and the adjusted one-month LIBOR plus 1.0%), plus the applicable margin. Under the CQP Revolving Facility, the applicable margin for LIBOR loans is 1.25% to 2.125% per annum, and the applicable margin for base rate loans is 0.25% to 1.125% per annum, in each case depending on our then-current rating. Interest on LIBOR loans is due and payable at the end of each applicable LIBOR period (and at the end of every three-month period within the LIBOR period, if any), and interest on base rate loans is due and payable at the end of each calendar quarter.

We pay a commitment fee equal to an annual rate of 30% of the margin for LIBOR loans multiplied by the average daily amount of the undrawn commitment, payable quarterly in arrears.

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. We have received authorization from the FERC to site, construct and operate Trains 1 through 6. 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, 2019:

	Train 6
Overall project completion percentage	43.7%
Completion percentage of:	
Engineering	91.5%
Procurement	60.9%
Subcontract work	37.4%
Construction	9.7%
Date of expected substantial completion	1H 2023

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 for a 30-year term, which commenced in May 2016, and non-FTA countries for a 20-year term, which commenced in June 2016, 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 for a 25-year term and non-FTA countries for a 20-year term, both of which commenced in December 2018, 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 for a 20-year term, which partially commenced in June 2019 and the remainder commenced in September 2019, in an amount up to a combined total of 503.3 Bcf/yr of natural gas (approximately 10 mtpa).

In each case, the terms of these authorizations began on the earlier of the date of first export thereunder or the date specified in the particular order. In addition, SPL received an order providing for a three-year makeup period with respect to each of the non-FTA orders for LNG volumes SPL was authorized but unable to export during any portion of the initial 20-year export period of such order.

The DOE issued orders authorizing SPL to export domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing January 2020, in an aggregate amount up to the equivalent of 600 Bcf of natural gas (however, exports under this order, when combined with exports under the orders above, may not exceed 1,509 Bcf/yr).

An application was filed in September 2019 to authorize 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 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. The application is currently pending before DOE.

Customers

SPL has entered into fixed price long-term SPAs generally with terms of 20 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. Under these SPAs, the customers will purchase LNG from SPL on a free on board ("FOB") basis for a price consisting of a fixed fee per MMBtu of LNG (a portion of which is subject to annual adjustment for inflation) plus a variable fee per MMBtu of LNG 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 by the end of 2020, 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 43 cargoes scheduled for delivery in 2020 at a price of 115% of Henry Hub plus $1.67 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, 2019, SPL had secured up to approximately 3,850 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 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 an optional third marine berth. As of December 31, 2019, we have incurred $1.1 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, 2019, 2018 and 2017, SPL recorded $104 million, $30 million and $23 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 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, 2019 and 2018 (in millions):

	December 31,	
	2019	2018
Senior notes (1)	$ 17,750	$ 16,250
Credit facilities outstanding balance (2)	—	—
Letters of credit issued (3)	414	425
Available commitments under credit facilities (3)	1,536	775
Total capital resources from borrowings and available commitments (4)	$ 19,700	$ 17,450

(1) Includes SPL's 5.625% Senior Secured Notes due 2021 , 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") 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 SPL Working Capital Facility and 2019 CQP Credit Facilities, inclusive of any portion of the 2019 CQP Credit Facilities that may be used for general corporate purposes.

(3) Consists of SPL Working Capital Facility and 2019 CQP Credit Facilities. Balance at December 31, 2018 did not include the letters of credit issued or available commitments under the terminated 2016 CQP Credit Facilities, which were not specifically for the Sabine Pass LNG Terminal.

(4) Does not include equity contributions that may be available from Cheniere's borrowings under its convertible notes, which may be used for the Sabine Pass LNG Terminal.

SPL Senior Notes

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.

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 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 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 indenture governing the 2037 SPL Senior Notes (the "2037 SPL Senior Notes Indenture") and the common indenture governing the remainder of the SPL Senior Notes (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 SPL Working Capital Facility. Under the 2037 SPL Senior Notes Indenture and the SPL Indenture, 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. 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.

SPL Working Capital Facility

In September 2015, SPL entered into the SPL Working Capital Facility with aggregate commitments of $1.2 billion, which was amended in May 2019 in connection with commercialization and financing Train 6 of the Liquefaction Project. The SPL Working Capital Facility is intended to be used for loans to SPL ("Working Capital Loans"), the issuance of letters of credit on behalf of SPL, as well as for swing line loans to SPL ("Swing Line Loans"), primarily for certain working capital requirements related to developing and placing into operation the Liquefaction Project. SPL may, from time to time, request increases in the commitments under the SPL Working Capital Facility of up to $760 million and incremental increases in commitments of up to an additional $390 million. As of December 31, 2019 and 2018, SPL had $786 million and $775 million of available commitments and $414 million and $425 million aggregate amount of issued letters of credit under the SPL Working Capital Facility, respectively. SPL did not have any outstanding borrowings under the SPL Working Capital Facility as of both December 31, 2019 and 2018.

The SPL Working Capital Facility matures on December 31, 2020, and the outstanding balance may be repaid, in whole or in part, at any time without premium or penalty upon three business days' notice. SPL LC Loans deemed made in connection with a draw upon a letter of credit have a term of up to one year. SPL Swing Line Loans terminate upon the earliest of (1) the maturity date or earlier termination of the SPL Working Capital Facility, (2) the date 15 days after such SPL Swing Line Loan is made and (3) the first borrowing date for a SPL Working Capital Loan or SPL Swing Line Loan occurring at least three business days following the date the SPL Swing Line Loan is made. SPL is required to reduce the aggregate outstanding principal amount of all Working Capital Loans to zero for a period of five consecutive business days at least once each year.

The SPL Working Capital Facility contains conditions precedent for extensions of credit, as well as customary affirmative and negative covenants. The obligations of SPL under the SPL Working Capital Facility are secured by substantially all of the assets of SPL as well as all of the membership interests in SPL on a *pari passu* basis with the SPL Senior Notes.

Restrictive Debt Covenants

As of December 31, 2019, 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 to work 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, 2019, 2018 and 2017 (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,		
	2019	2018	2017
Operating cash flows	$ 1,547	$ 1,874	$ 977
Investing cash flows	(1,332)	(804)	(1,290)
Financing cash flows	206	(1,118)	1,297
Net increase (decrease) in cash, cash equivalents and restricted cash	421	(48)	984
Cash, cash equivalents and restricted cash—beginning of period	1,541	1,589	605
Cash, cash equivalents and restricted cash—end of period	$ 1,962	$ 1,541	$ 1,589

Operating Cash Flows

Our operating cash net inflows during the years ended December 31, 2019, 2018 and 2017 were $1,547 million, $1,874 million and $977 million, respectively. 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. The $897 million increase in operating cash inflows in 2018 compared to 2017 was primarily related to increased cash receipts from the sale of LNG cargoes, partially offset by increased operating costs and expenses as a result of the additional Trains that were operating at the Liquefaction Project in 2018.

Investing Cash Flows

Investing cash net outflows during the years ended December 31, 2019, 2018 and 2017 were $1,332 million, $804 million and $1,290 million, respectively, and were primarily used to fund the construction costs for the Liquefaction Project. These costs are capitalized as construction-in-process until achievement of substantial completion.

Financing Cash Flows

Financing cash net inflows of $206 million during the year ended December 31, 2019 were primarily a result of:

- issuance of an aggregate principal amount of $1.5 billion of the 2029 CQP Senior Notes, which was used to prepay the outstanding balance of the term loan under the 2019 CQP Credit Facilities;
- $35 million of debt issuance costs related to the up-front fees paid upon the issuance of the 2019 CQP Credit Facilities and 2029 CQP Senior Notes;
- $730 million of borrowings and repayments under the 2019 CQP Credit Facilities; and
- $1,260 million of distributions to unitholders.

Financing cash net outflows of $1,118 million during the year ended December 31, 2018 were primarily a result of:

- issuance of an aggregate principal amount of $1.1 billion of the 2026 CQP Senior Notes, which was used to prepay $1.1billion of the outstanding borrowings under the 2016 CQP Credit Facilities;
- $8 million of debt issuance costs related to up-front fees paid upon the closing of the above transactions;
- $7 million in debt extinguishment costs related to the prepayment of the 2016 CQP Credit Facilities; and
- $1.1 billion in distributions to unitholders.

Financing cash net inflows during the year ended December 31, 2017 were $1,297 million, primarily as a result of:

- issuances of SPL's senior notes for an aggregate principal amount of $2.15 billion;

- $55 million of borrowings and $369 million of repayments made under the credit facilities SPL entered into in June 2015 (the "SPL Credit Facilities");
- issuance of an aggregate principal amount of $1.5 billion of the 2025 CQP Senior Notes, which was used to prepay $1.5 billion of the outstanding borrowings under the 2016 CQP Credit Facilities;
- $110 million of borrowings and $334 million of repayments made under the SPL Working Capital Facility;
- $50 million of debt issuance costs related to up-front fees paid upon the closing of these transactions; and
- $294 million of distributions to unitholders.

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, 2019, 2018 and 2017:

				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 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
November 14, 2017	July 1 - September 30, 2017	$ 0.440	$ 0.440	$ 153	$ 60	$ 4	$ —
August 11, 2017	April 1 - June 30, 2017	0.425	—	24	—	0.5	—
May 15, 2017	January 1 - March 31, 2017	0.425	—	24	—	0.5	—
February 13, 2017	October 1 - December 31, 2016	0.425	—	24	—	0.5	—

On January 28, 2020, we declared a $0.63 distribution per common unit and subordinated unit and the related distribution to our general partner and incentive distribution right holders to be paid on February 14, 2020 to unitholders of record as of February 7, 2020 for the period from October 1, 2019 to December 31, 2019.

The subordinated units will receive distributions only to the extent we have available cash above the initial quarterly distributions requirement for our common unitholders and general partner along with certain reserves. Such available cash could be generated through new business development. The ending of the subordination period and conversion of the subordinated units into common units will depend upon future business development.

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, 2019 (in millions):

	Payments Due By Period (1)				
	Total	2020	2021-2022	2023-2024	Thereafter
Debt (2)	$ 17,750	$ —	$ 3,000	$ 3,500	$ 11,250
Interest payments (2)	5,461	955	1,710	1,376	1,420
Operating lease obligations (3)	164	9	20	19	116
Purchase obligations: (4)					
Construction obligations (5)	901	462	398	41	—
Natural gas supply, transportation and storage service agreements (6)	7,305	2,248	2,183	960	1,914
Other purchase obligations (7)	2,400	198	394	394	1,414
Other non-current liabilities—affiliate (8)	22	2	5	5	10
Total	$ 34,003	$ 3,874	$ 7,710	$ 6,295	$ 16,124

(1) Agreements in force as of December 31, 2019 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2019.

(2) Based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2019. 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, 2019 for Trains 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 are based on estimated forward prices and basis spreads as of December 31, 2019.

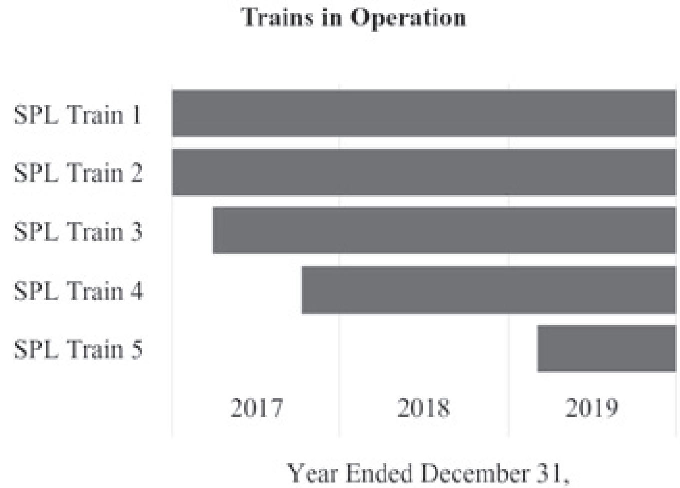
(7) Other purchase obligations primarily relate to payments under SPL's partial TUA assignment agreement with Total as discussed in Note 13—Revenues from Contracts with Customers of our Notes to Consolidated Financial Statements.

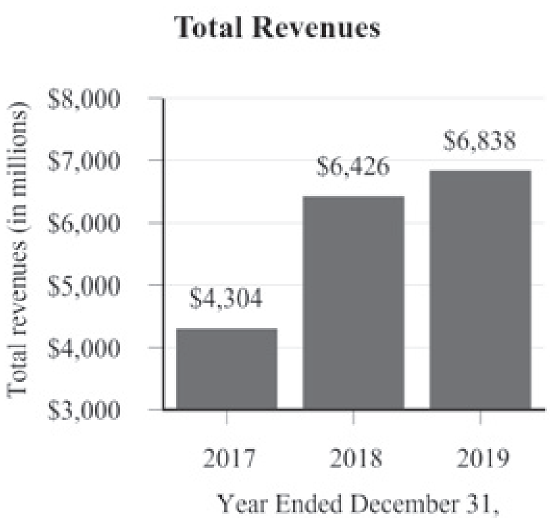
(8) Other non-current liabilities—affiliate primarily relate to obligations to Cheniere Marketing related to the Cooperative Endeavor Agreement, as discussed in Note 14—Related Party Transactions of our Notes to Consolidated Financial Statements.

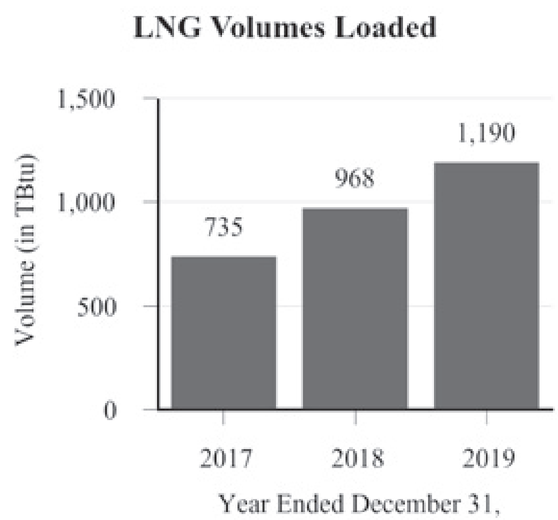
In addition, as of December 31, 2019, we had $414 million aggregate amount of issued letters of credit under our credit facilities.

Results of Operations

The following charts summarize the number of Trains that were in operation during the years ended December 31, 2019, 2018 and 2017 and total revenues and total LNG volumes loaded (including both operational and commissioning volumes) for the respective periods:







Our consolidated net income was $1.2 billion, or $2.25 per common unit (basic and diluted), in the year ended December 31, 2019, compared to $1.3 billion, or $2.51 per common unit (basic and diluted), in the year ended December 31, 2018. This $99 million decrease in net income 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.

Our consolidated net income was $490 million, or $1.32 loss per common unit (basic and diluted), in the year ended December 31, 2017. This $784 million increase in net income in 2018 was primarily a result of increased income from operations due to additional Trains operating between the periods and decreased loss on modification or extinguishment of debt, which were partially offset by increased interest expense, net of amounts capitalized.

We enter into derivative instruments to manage our exposure to changing interest rates and 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)	**2019**	**2018**	**Change**	**2017**	**Change**
LNG revenues	$ 5,211	$ 4,827	$ 384	$ 2,635	$ 2,192
LNG revenues—affiliate	1,312	1,299	13	1,389	(90)
Regasification revenues	266	261	5	260	1
Other revenues	49	39	10	20	19
Total revenues	$ 6,838	$ 6,426	$ 412	$ 4,304	$ 2,122
LNG volumes recognized as revenues (in TBtu)	1,180	955	225	684	271

2019 vs. 2018 and 2018 vs. 2017

We begin recognizing LNG revenues from the Liquefaction Project following the substantial completion and the commencement of operating activities of the respective Trains. The increase in LNG revenues during each of the years was primarily attributable to the increased volume of LNG sold following the achievement of substantial completion of the Trains, as well as increased revenues per MMBtu between the years ended December 31, 2018 and 2017 but partially offset by decreased revenues per MMBtu between the years ended December 31, 2019 and 2018. 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, 2018 and 2017, we realized offsets to LNG terminal costs of $48 million corresponding to 10 TBtu of LNG, $94 million corresponding to 13 TBtu of LNG and $301 million corresponding to 51 TBtu of LNG, respectively, that were related to the sale of commissioning cargoes.

Also included in LNG revenues are gains and losses from derivative instruments and the sale of natural gas procured for the liquefaction process. We recognized revenues of $150 million, $151 million and $29 million during the years ended December 31, 2019, 2018 and 2017, respectively, related to derivative instruments and other revenues from these transactions.

Operating costs and expenses

	Year Ended December 31,				
(in millions)	**2019**	**2018**	**Change**	**2017**	**Change**
Cost of sales	$ 3,374	$ 3,403	$ (29)	$ 2,320	$ 1,083
Cost of sales—affiliate	7	—	7	—	—
Operating and maintenance expense	632	409	223	292	117
Operating and maintenance expense—affiliate	138	117	21	100	17
Development expense	—	2	(2)	3	(1)
General and administrative expense	11	11	—	12	(1)
General and administrative expense—affiliate	102	73	29	80	(7)
Depreciation and amortization expense	527	424	103	339	85
Impairment expense and loss on disposal of assets	7	8	(1)	—	8
Other	—	—	—	2	(2)
Total operating costs and expenses	$ 4,798	$ 4,447	$ 351	$ 3,148	$ 1,299

2019 vs. 2018 and 2018 vs. 2017

Our total operating costs and expenses increased during the year ended December 31, 2019 from the years ended December 31, 2018 and 2017, primarily as a result of additional Trains that were operating between each of the periods. During the year ended December 31, 2019, we further incurred increased TUA reservation charges paid to 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, 2019 from the comparable period in 2018 primarily 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. The increase during the year ended December 31, 2018 from the comparable period in 2017 was primarily related to the increase in the volume of natural gas feedstock related to our LNG sales. Cost of sales also includes variable transportation and storage costs and other costs to convert natural gas into LNG.

Operating and maintenance expense 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, 2019 from the comparable 2018 and 2017 periods was primarily related to: (1) increased TUA reservation charges paid to Total from payments under the partial TUA assignment agreement, (2) increased third-party service and maintenance contract costs, including increased cost of turnaround and related activities at the Liquefaction Project during 2019 and (3) 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. 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, 2019, 2018 and 2017 as a result of an increase in operational Trains, as the related assets began depreciating upon reaching substantial completion.

Other expense (income)

	Year Ended December 31,				
(in millions)	2019	2018	Change	2017	Change
Interest expense, net of capitalized interest	$ 885	$ 733	$ 152	$ 614	$ 119
Loss on modification or extinguishment of debt	13	12	1	67	(55)
Derivative gain, net	—	(14)	14	(4)	(10)
Other income	(31)	(26)	(5)	(11)	(15)
Other income—affiliate	(2)	—	(2)	—	—
Total other expense	$ 865	$ 705	$ 160	$ 666	$ 39

2019 vs. 2018 and 2018 vs. 2017

Interest expense, net of capitalized interest, increased during the year ended December 31, 2019 from the comparable 2018 and 2017 periods 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, 2019, 2018 and 2017, we incurred $972 million, $936 million and $902 million of total interest cost, respectively, of which we capitalized $87 million, $203 million and $288 million, respectively, which was primarily related to interest costs incurred for the construction of the Liquefaction Project.

Loss on modification or extinguishment of debt increased during the year ended December 31, 2019 compared to the year ended December 31, 2018 and decreased between the year ended December 31, 2018 and the year ended December 31, 2017. The loss on modification or extinguishment of debt recognized in each of the years was related to the incurrence of third party fees and write off of unamortized debt issuance costs recognized upon refinancing our credit facilities with senior notes or upon amendment and restatement of our credit facilities.

Derivative gain, net decreased during the year ended December 31, 2019 compared to the years ended December 31, 2018 and 2017, 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. The increase in derivative gain during the year ended December 31, 2018 compared to the year ended December 31, 2017 was primarily due to a favorable shift in the long-term forward LIBOR curve between the periods.

Off-Balance Sheet Arrangements

As of December 31, 2019, 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 interest rate swaps, financial commodity derivative contracts transacted in an over-the-counter market and physical commodity contracts. We value our interest rate swaps using observable inputs including interest rate curves, risk adjusted discount rates, credit spreads and other relevant data. 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, 2019		December 31, 2018	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
Liquefaction Supply Derivatives	$ 24	$ 1	$ (43)	$ 7

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

CHENIERE ENERGY PARTNERS, L.P.

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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, 2019, 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, 2019, 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/ Michael J. Wortley
	Jack A. Fusco President and Chief Executive Officer (Principal Executive Officer)		Michael J. Wortley Executive Vice President and Chief Financial Officer (Principal Financial Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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, 2019 and 2018, the related consolidated statements of income, partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, 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, 2019, 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 24, 2020 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 judgment. The communication of 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 note 8 to the consolidated financial statements, the Partnership recorded fair value of level 3 physical liquefaction supply derivatives of $24 million, as of December 31, 2019. 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 Partnership's level 3 physical liquefaction supply derivatives is developed through the use of internal models, using observable and unobservable market commodity prices.

We identified the evaluation of the fair value of the Partnership's level 3 physical liquefaction supply derivatives as a critical audit matter. Specifically, there is subjectivity in certain assumptions used to estimate the fair value, such as the use of liquidity assumptions and adjustments for unobservable commodity prices.

The primary procedures we performed to address this critical audit matter include the following. We tested 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:

- Assessing the models used by the Partnership in its valuation by developing independent fair value estimates and comparing the independently developed estimates to the Partnership's fair value estimates, and
- Testing the market unobservable forward price curve adjustments and liquidity assumptions by comparing to market data, such as quoted or published forward prices for similar commodities.

In addition, we evaluated the Partnership's assumptions for unobservable commodity prices by comparing to market or third party data, such as 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 24, 2020

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:

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, 2019, 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, 2019, 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, 2019 and 2018, the related consolidated statements of income, partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements), and our report dated February 24, 2020 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 24, 2020

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in millions, except per unit data)

	December 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,781	$ —
Restricted cash	181	1,541
Accounts and other receivables	297	348
Accounts receivable—affiliate	105	114
Advances to affiliate	158	228
Inventory	116	99
Derivative assets	17	6
Other current assets	51	20
Other current assets—affiliate	1	—
Total current assets	2,707	2,356
Property, plant and equipment, net	16,368	15,390
Operating lease assets, net	94	—
Debt issuance costs, net	15	13
Non-current derivative assets	32	31
Other non-current assets, net	168	184
Total assets	$ 19,384	$ 17,974
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accounts payable	$ 40	$ 15
Accrued liabilities	709	821
Due to affiliates	46	49
Deferred revenue	155	116
Deferred revenue—affiliate	1	1
Current operating lease liabilities	6	—
Derivative liabilities	9	66
Total current liabilities	966	1,068
Long-term debt, net	17,579	16,066
Non-current operating lease liabilities	87	—
Non-current derivative liabilities	16	14
Other non-current liabilities	1	4
Other non-current liabilities—affiliate	20	22
Commitments and contingencies (see Note 16)		
Partners' equity		
Common unitholders' interest (348.6 million units issued and outstanding at December 31, 2019 and 2018)	1,792	1,806
Subordinated unitholders' interest (135.4 million units issued and outstanding at December 31, 2019 and 2018)	(996)	(990)
General partner's interest (2% interest with 9.9 million units issued and outstanding at December 31, 2019 and 2018)	(81)	(16)
Total partners' equity	715	800
Total liabilities and partners' equity	$ 19,384	$ 17,974

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

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

	Year Ended December 31,		
	2019	2018	2017
Revenues			
LNG revenues	$ 5,211	$ 4,827	$ 2,635
LNG revenues—affiliate	1,312	1,299	1,389
Regasification revenues	266	261	260
Other revenues	49	39	20
Total revenues	6,838	6,426	4,304
Operating costs and expenses			
Cost of sales (excluding depreciation and amortization expense shown separately below)	3,374	3,403	2,320
Cost of sales—affiliate	7	—	—
Operating and maintenance expense	632	409	292
Operating and maintenance expense—affiliate	138	117	100
Development expense	—	2	3
General and administrative expense	11	11	12
General and administrative expense—affiliate	102	73	80
Depreciation and amortization expense	527	424	339
Impairment expense and loss on disposal of assets	7	8	2
Total operating costs and expenses	4,798	4,447	3,148
Income from operations	2,040	1,979	1,156
Other income (expense)			
Interest expense, net of capitalized interest	(885)	(733)	(614)
Loss on modification or extinguishment of debt	(13)	(12)	(67)
Derivative gain, net	—	14	4
Other income	31	26	11
Other income—affiliate	2	—	—
Total other expense	(865)	(705)	(666)
Net income	$ 1,175	$ 1,274	$ 490
Basic and diluted net income (loss) per common unit	$ 2.25	$ 2.51	$ (1.32)
Weighted average number of common units outstanding used for basic and diluted net income (loss) per common unit calculation	348.6	348.6	178.5

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		Class B Unitholders' Interest		Subordinated Unitholder's Interest		General Partner's Interest		Total Partners' Equity
	Units	Amount	Units	Amount	Units	Amount	Units	Amount	
Balance at December 31, 2016	57.1	$ 130	145.3	$ 62	135.4	$ 240	6.9	$ 11	$ 443
Net income	—	294	—	—	—	186	—	10	490
Distributions									
Common units, $1.715/unit	—	(226)	—	—	—	—	—	—	(226)
Subordinated units, $0.44/unit	—	—	—	—	—	(59)	—	—	(59)
General partner units	—	—	—	—	—	—	—	(9)	(9)
Conversion of Class B units into common units	291.5	2,066	(145.3)	(2,066)	—	—	3.0	—	—
Amortization of beneficial conversion feature of Class B units	—	(594)	—	2,004	—	(1,410)	—	—	—
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

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,		
	2019	2018	2017
Cash flows from operating activities			
Net income	$ 1,175	$ 1,274	$ 490
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	527	424	339
Amortization of debt issuance costs, deferred commitment fees, premium and discount	34	30	36
Loss on modification or extinguishment of debt	13	12	67
Total losses (gains) on derivatives, net	(72)	87	20
Net cash provided by (used for) settlement of derivative instruments	5	32	(16)
Impairment expense and loss on disposal of assets	7	8	2
Other	11	5	6
Other—affiliate	(2)	—	—
Changes in operating assets and liabilities:			
Accounts and other receivables	16	(122)	(101)
Accounts receivable—affiliate	9	47	(62)
Advances to affiliate	(41)	(84)	(12)
Inventory	(16)	(5)	13
Accounts payable and accrued liabilities	(126)	183	210
Due to affiliates	6	(6)	(42)
Deferred revenue	39	3	34
Other, net	(36)	(12)	(5)
Other, net—affiliate	(2)	(2)	(2)
Net cash provided by operating activities	1,547	1,874	977
Cash flows from investing activities			
Property, plant and equipment, net	(1,331)	(804)	(1,290)
Other	(1)	—	—
Net cash used in investing activities	(1,332)	(804)	(1,290)
Cash flows from financing activities			
Proceeds from issuances of debt	2,230	1,100	3,814
Repayments of debt	(730)	(1,090)	(2,173)
Debt issuance and deferred financing costs	(35)	(8)	(50)
Distributions to owners	(1,260)	(1,113)	(294)
Other	1	(7)	—
Net cash provided by (used in) financing activities	206	(1,118)	1,297
Net increase (decrease) in cash, cash equivalents and restricted cash	421	(48)	984
Cash, cash equivalents and restricted cash—beginning of period	1,541	1,589	605
Cash, cash equivalents and restricted cash—end of period	$ 1,962	$ 1,541	$ 1,589

Balances per Consolidated Balance Sheets:

	December 31,	
	2019	2018
Cash and cash equivalents	$ 1,781	$ —
Restricted cash	181	1,541
Total cash, cash equivalents and restricted cash	$ 1,962	$ 1,541

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 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. 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, 2019, Cheniere owned 48.6% of our limited partner interest in the form of 104.5 million of our common units and 135.4 million of our subordinated units. Cheniere also owns 100% of our general partner interest and our incentive distribution rights.

NOTE 2—UNITHOLDERS' EQUITY

The common units and subordinated 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.

The holders of common units have the right to receive initial quarterly distributions of $0.425 per common unit, plus any arrearages thereon, before any distribution is made to the holders of the subordinated units. The holders of subordinated units will receive distributions only to the extent we have available cash above the initial quarterly distribution requirement for our common unitholders and general partner and certain reserves. Subordinated units will convert into common units on a one-for-one basis when we meet financial tests specified in the partnership agreement. Although common and subordinated unitholders are not obligated to fund losses of the Partnership, their capital accounts, which would be considered in allocating the net assets of the Partnership were it to be liquidated, continue 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 incentive distribution rights ("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, 2019, Cheniere, Blackstone CQP Holdco and the public owned a 48.6%, 40.3% and 9.1% interest in us, respectively. Cheniere's ownership percentage includes its subordinated units and Blackstone CQP Holdco's ownership percentage excludes any common units that may be deemed to be beneficially owned by Blackstone Group, an affiliate of Blackstone CQP Holdco.

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

Recent Accounting Standards

We adopted Accounting Standards Update ("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 have elected the practical expedients to (1) carryforward prior conclusions related to lease identification and classification for existing leases, (2) combine lease and non-lease components of an arrangement for all classes of leased assets, (3) omit short-term leases with a term of 12 months or less from recognition on the balance sheet and (4) carryforward our existing accounting for land easements not previously accounted for as leases. See Note 12—Leases for additional information on our leases following the adoption of this standard.

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 in Note 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 allowances for doubtful accounts. We periodically review the collectability on our accounts receivable and recognize an allowance if there is probability of non-collection, based on historical write-off and customer-specific factors. We did not have an allowance on our accounts receivable as of December 31, 2019 and 2018.

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.

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, 2019, 2018 and 2017. See Note 8—Derivative Instruments for additional details about our derivative instruments.

Leases

Following the adoption of ASC 842, 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, 2019. 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 of 20 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 into two 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, 2019, the tax basis of our assets and liabilities was $5.7 billion less than the reported amounts of our assets and liabilities. See Note 14—Related Party Transactions for details about income taxes under our tax sharing agreements.

Business Segment

Our liquefaction and regasification operations at the Sabine Pass LNG terminal represent a single reportable segment. Our chief operating decision maker reviews the financial results of 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, 2019 and 2018, restricted cash consisted of the following (in millions):

	December 31,	
	2019	2018
Current restricted cash		
Liquefaction Project	$ 181	$ 756
Cash held by us and our guarantor subsidiaries	—	785
Total current restricted cash	$ 181	$ 1,541

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.

The cash held by us and our guarantor subsidiaries was restricted in use under the terms of the previous $2.8 billion credit facilities (the "2016 CQP Credit Facilities") and the related depositary agreement governing the extension of credit to us, but is no longer restricted following the termination of the 2016 CQP Credit Facilities. Amounts not classified as restricted have been reserved by our general partner under the terms of our partnership agreement.

NOTE 5—ACCOUNTS AND OTHER RECEIVABLES

As of December 31, 2019 and 2018, accounts and other receivables consisted of the following (in millions):

	December 31,	
	2019	2018
SPL trade receivable	$ 283	$ 330
Other accounts receivable	14	18
Total accounts and other receivables	$ 297	$ 348

NOTE 6—INVENTORY

As of December 31, 2019 and 2018, inventory consisted of the following (in millions):

	December 31, 2019	December 31, 2018
Natural gas	$ 9	$ 28
LNG	27	6
Materials and other	80	65
Total inventory	$ 116	$ 99

NOTE 7—PROPERTY, PLANT AND EQUIPMENT

As of December 31, 2019 and 2018, property, plant and equipment, net consisted of the following (in millions):

	December 31, 2019	December 31, 2018
LNG terminal costs		
LNG terminal and interconnecting pipeline facilities	$ 16,894	$ 12,760
LNG terminal construction-in-process	1,275	3,913
Accumulated depreciation	(1,807)	(1,290)
Total LNG terminal costs, net	16,362	15,383
Fixed assets		
Fixed assets	27	26
Accumulated depreciation	(21)	(19)
Total fixed assets, net	6	7
Property, plant and equipment, net	$ 16,368	$ 15,390

Depreciation expense was $523 million, $413 million and $331 million during the years ended December 31, 2019, 2018 and 2017, respectively.

We realized offsets to LNG terminal costs of $48 million, $94 million and $301 million during the years ended December 31, 2019, 2018 and 2017, respectively, that were 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 the following derivative instruments that are reported at fair value:

- interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under certain credit facilities ("Interest Rate Derivatives") and
- 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, 2019 and 2018, 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, 2019				December 31, 2018			
	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)	$ 3	$ (3)	$ 24	$ 24	$ 5	$ (23)	$ (25)	$ (43)

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, 2019 and 2018, 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, 2019:

	Net Fair Value Asset (in millions)	Valuation Approach	Significant Unobservable Input	Significant Unobservable Inputs Range
Physical Liquefaction Supply Derivatives	$24	Market approach incorporating present value techniques	Henry Hub basis spread	$(0.350) - $0.058

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, 2019, 2018 and 2017 (in millions):

	Year Ended December 31,		
	2019	2018	2017
Balance, beginning of period	$ (25)	$ 43	$ 79
Realized and mark-to-market gains (losses):			
Included in cost of sales	6	(3)	(37)
Purchases and settlements:			
Purchases	—	(37)	14
Settlements	42	(29)	(12)
Transfers out of Level 3 (1)	1	1	(1)
Balance, end of period	$ 24	$ (25)	$ 43
Change in unrealized gains (losses) relating to instruments still held at end of period	$ 6	$ (3)	$ (37)

(1) Transferred to Level 2 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

In October 2018, we settled the interest rate swaps ("CQP Interest Rate Derivatives") we previously had to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the 2016 CQP Credit Facilities.

In March 2017, SPL settled the interest rate swaps ("SPL Interest Rate Derivatives") it previously had to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the credit facilities it entered into in June 2015.

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, 2019, 2018 and 2017 (in millions):

	Year Ended December 31,		
	2019	2018	2017
CQP Interest Rate Derivatives gain	—	14	6
SPL Interest Rate Derivatives loss	—	—	(2)

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 approximately 3,663 TBtu and 2,978 TBtu as of December 31, 2019 and 2018, respectively.

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 Sheet Location	**December 31, 2019**	**December 31, 2018**
Derivative assets	$ 17	$ 6
Non-current derivative assets	32	31
Total derivative assets	49	37
Derivative liabilities	(9)	(66)
Non-current derivative liabilities	(16)	(14)
Total derivative liabilities	(25)	(80)
Derivative asset (liability), net	$ 24	$ (43)

(1) Does not include collateral posted with counterparties by us of $2 million and $1 million for such contracts, which are included in other current assets in our Consolidated Balance Sheets as of December 31, 2019 and 2018, respectively.

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, 2019, 2018 and 2017 (in millions):

		Year Ended December 31,		
	Consolidated Statement of Income Location (1)	**2019**	**2018**	**2017**
Liquefaction Supply Derivatives gain (loss)	LNG revenues	$ 1	$ (1)	$ —
Liquefaction Supply Derivatives gain (loss)	Cost of sales	71	(100)	(24)

(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 Sheet 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):

Offsetting Derivative Assets (Liabilities)	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
As of December 31, 2019			
Liquefaction Supply Derivatives	$ 51	$ (2)	$ 49
Liquefaction Supply Derivatives	(27)	2	(25)
As of December 31, 2018			
Liquefaction Supply Derivatives	$ 63	$ (26)	$ 37
Liquefaction Supply Derivatives	(92)	12	(80)

NOTE 9—OTHER NON-CURRENT ASSETS

As of December 31, 2019 and 2018, other non-current assets, net consisted of the following (in millions):

	December 31,	
	2019	2018
Advances made to municipalities for water system enhancements	$ 87	$ 90
Advances and other asset conveyances to third parties to support LNG terminal	35	36
Tax-related prepayments and receivables	17	17
Information technology service prepayments	6	20
Advances made under EPC and non-EPC contracts	15	14
Other	8	7
Total other non-current assets, net	$ 168	$ 184

NOTE 10—ACCRUED LIABILITIES

As of December 31, 2019 and 2018, accrued liabilities consisted of the following (in millions):

	December 31,	
	2019	2018
Interest costs and related debt fees	$ 241	$ 224
Accrued natural gas purchases	325	518
LNG terminal and related pipeline costs	135	79
Other accrued liabilities	8	—
Total accrued liabilities	$ 709	$ 821

NOTE 11—DEBT

As of December 31, 2019 and 2018, our debt consisted of the following (in millions):

	December 31,	
	2019	2018
Long-term debt:		
SPL		
5.625% Senior Secured Notes due 2021 (“2021 SPL Senior Notes”)	$ 2,000	$ 2,000
6.25% Senior Secured Notes due 2022 (“2022 SPL Senior Notes”)	1,000	1,000
5.625% Senior Secured Notes due 2023 (“2023 SPL Senior Notes”)	1,500	1,500
5.75% Senior Secured Notes due 2024 (“2024 SPL Senior Notes”)	2,000	2,000
5.625% Senior Secured Notes due 2025 (“2025 SPL Senior Notes”)	2,000	2,000
5.875% Senior Secured Notes due 2026 (“2026 SPL Senior Notes”)	1,500	1,500
5.00% Senior Secured Notes due 2027 (“2027 SPL Senior Notes”)	1,500	1,500
4.200% Senior Secured Notes due 2028 (“2028 SPL Senior Notes”)	1,350	1,350
5.00% Senior Secured Notes due 2037 (“2037 SPL Senior Notes”)	800	800
Cheniere Partners		
5.250% Senior Notes due 2025 (“2025 CQP Senior Notes”)	1,500	1,500
5.625% Senior Notes due 2026 (“2026 CQP Senior Notes”)	1,100	1,100
4.500% Senior Notes due 2029 (“2029 CQP Senior Notes”)	1,500	—
2016 CQP Credit Facilities	—	—
CQP Credit Facilities executed in 2019 (“2019 CQP Credit Facilities”)	—	—
Unamortized premium, discount and debt issuance costs, net	(171)	(184)
Total long-term debt, net	17,579	16,066
Current debt:		
$1.2 billion SPL Working Capital Facility (“SPL Working Capital Facility”)	—	—
Total debt, net	$ 17,579	$ 16,066

Below is a schedule of future principal payments that we are obligated to make on our outstanding debt at December 31, 2019 (in millions):

Years Ending December 31,	Principal Payments
2020	$ —
2021	2,000
2022	1,000
2023	1,500
2024	2,000
Thereafter	11,250
Total	$ 17,750

Senior Notes

SPL Senior Notes

The terms of the 2021 SPL Senior Notes, 2022 SPL Senior Notes, 2023 SPL Senior Notes, 2024 SPL Senior Notes, 2025 SPL Senior Notes, 2026 SPL Senior Notes, 2027 SPL Senior Notes and 2028 SPL Senior Notes (collectively with the 2037 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 customary 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. 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. Interest on the SPL Senior Notes is payable semi-annually in arrears.

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 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 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.

CQP Senior Notes

In September 2019, we issued an aggregate principal amount of $1.5 billion of the 2029 CQP Senior Notes. The proceeds of the offering were used to prepay the outstanding balance of the $750 million term loan under the 2019 CQP Credit Facilities ("CQP Term Facility") and for general corporate purposes, including funding future capital expenditures in connection with the construction of Train 6 at the Liquefaction Project, resulting in the recognition of debt modification and extinguishment costs of $13 million for the year ended December 31, 2019. Borrowings under the 2029 CQP Senior Notes accrue interest at a fixed rate of 4.500% per annum. As of December 31, 2019, only the $750 million revolving credit facility ("CQP Revolving Facility"), all of which is undrawn, remains as part of the 2019 CQP Credit Facilities.

The 2025 CQP Senior Notes, 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 (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 customary 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. Interest on the CQP Senior Notes is payable semi-annually in arrears.

At any time prior to October 1, 2020 for the 2025 CQP Senior Notes, 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, 2020 for the 2025 CQP Senior Notes, 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 105.250% of the aggregate principal amount of the 2025 CQP Senior Notes, 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 on or after October 1, 2020 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 rights and 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.

Credit Facilities

Below is a summary of our credit facilities outstanding as of December 31, 2019 (in millions):

	SPL Working Capital Facility	2019 CQP Credit Facilities
Original facility size	$ 1,200	$ 1,500
Less:		
Outstanding balance	—	—
Commitments prepaid or terminated	—	750
Letters of credit issued	414	—
Available commitment	$ 786	$ 750
Interest rate on available balance	LIBOR plus 1.75% or base rate plus 0.75%	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	December 31, 2020	May 29, 2024

SPL Working Capital Facility

In September 2015, SPL entered into the SPL Working Capital Facility with aggregate commitments of $1.2 billion, which was amended in May 2019 in connection with commercialization and financing of Train 6 of the Liquefaction Project. The SPL Working Capital Facility is intended to be used for loans to SPL ("SPL Working Capital Loans"), the issuance of letters of credit on behalf of SPL, as well as for swing line loans to SPL ("SPL Swing Line Loans"), primarily for certain working capital requirements related to developing and placing into operation the Liquefaction Project. SPL may, from time to time, request increases in the commitments under the SPL Working Capital Facility of up to $760 million and incremental increases in commitments of up to an additional $390 million.

Loans under the SPL Working Capital Facility accrue interest at a variable rate per annum equal to LIBOR or the base rate (equal to the highest of the senior facility agent's published prime rate, the federal funds effective rate, as published by the Federal Reserve Bank of New York, plus 0.50% and one month LIBOR plus 0.50%), plus the applicable margin. The applicable margin for LIBOR loans under the SPL Working Capital Facility is 1.75% per annum, and the applicable margin for base rate loans under the SPL Working Capital Facility is 0.75% per annum. Interest on SPL Swing Line Loans and loans deemed made in connection with a draw upon a letter of credit ("SPL LC Loans") is due and payable on the date the loan becomes due. Interest on LIBOR loans is due and payable at the end of each applicable LIBOR period, and interest on base rate loans is due and payable at the end of each fiscal quarter. However, if such base rate loan is converted into a LIBOR loan, interest is due and payable on that date. Additionally, if the loans become due prior to such periods, the interest also becomes due on that date.

SPL pays (1) a commitment fee equal to an annual rate of 0.70% on the average daily amount of the excess of the total commitment amount over the principal amount outstanding without giving effect to any outstanding SPL Swing Line Loans and (2) a letter of credit fee equal to an annual rate of 1.75% of the undrawn portion of all letters of credit issued under the SPL Working Capital Facility. If draws are made upon a letter of credit issued under the SPL Working Capital Facility and SPL does not elect for such draw (an "SPL LC Draw") to be deemed an SPL LC Loan, SPL is required to pay the full amount of the SPL LC Draw on or prior to the business day following the notice of the SPL LC Draw. An SPL LC Draw accrues interest at an annual rate of 2.0% plus the base rate. As of December 31, 2019, no SPL LC Draws had been made upon any letters of credit issued under the SPL Working Capital Facility.

The SPL Working Capital Facility matures on December 31, 2020, and the outstanding balance may be repaid, in whole or in part, at any time without premium or penalty upon three business days' notice. SPL LC Loans have a term of up to one year. SPL Swing Line Loans terminate upon the earliest of (1) the maturity date or earlier termination of the SPL Working Capital Facility, (2) the date 15 days after such SPL Swing Line Loan is made and (3) the first borrowing date for a SPL Working Capital Loan or SPL Swing Line Loan occurring at least three business days following the date the SPL Swing Line Loan is made. SPL is required to reduce the aggregate outstanding principal amount of all SPL Working Capital Loans to zero for a period of five consecutive business days at least once each year.

The SPL Working Capital Facility contains conditions precedent for extensions of credit, as well as customary affirmative and negative covenants. The obligations of SPL under the SPL Working Capital Facility are secured by substantially all of the assets of SPL as well as all of the membership interests in SPL on a *pari passu* basis with the SPL Senior Notes.

CQP Credit Facilities

In May 2019, we terminated the remaining commitments under the 2016 CQP Credit Facilities and entered into the 2019 CQP Credit Facilities, which consisted of the $750 million CQP Term Facility, which was prepaid and terminated upon issuance of the 2029 CQP Senior Notes in September 2019, and the $750 million 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.

Loans under the 2019 CQP Credit Facilities accrue interest at a variable rate per annum equal to LIBOR or the base rate (equal to the highest of the prime rate, the federal funds effective rate, as published by the Federal Reserve Bank of New York, plus 0.50%, and the adjusted one-month LIBOR plus 1.0%), plus the applicable margin. Under the CQP Term Facility, the applicable margin for LIBOR loans was 1.50% per annum, and the applicable margin for base rate loans was 0.50% per annum. Under the CQP Revolving Facility, the applicable margin for LIBOR loans is 1.25% to 2.125% per annum, and the applicable margin for base rate loans is 0.25% to 1.125% per annum, in each case depending on our then-current rating. Interest on LIBOR loans is due and payable at the end of each applicable LIBOR period (and at the end of every three-month period within the LIBOR period, if any), and interest on base rate loans is due and payable at the end of each calendar quarter.

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).

Restrictive Debt Covenants

As of December 31, 2019, we and SPL were in compliance with all covenants related to our respective debt agreements.

Interest Expense

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

	Year Ended December 31,		
	2019	2018	2017
Total interest cost	$ 972	$ 936	$ 902
Capitalized interest	(87)	(203)	(288)
Total interest expense, net	$ 885	$ 733	$ 614

Fair Value Disclosures

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

	December 31, 2019		December 31, 2018	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Senior notes (1)	$ 16,950	$ 18,320	$ 15,450	$ 15,672
2037 SPL Senior Notes (2)	800	934	800	817
Credit facilities (3)	—	—	—	—

(1) Includes SPL Senior Notes except the 2037 SPL Senior Notes and the CQP Senior Notes. 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 our stock price and interest rates based on debt issued by parties with comparable credit ratings to us and inputs that are not observable in the market.

(3) Includes SPL Working Capital Facility, 2016 CQP Credit Facilities and 2019 CQP Credit Facilities. 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.

ASC 842 requires a lessee to recognize leases on its 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):

	Consolidated Balance Sheet Location	December 31, 2019
Right-of-use assets—Operating	Operating lease assets, net	$ 94
Current operating lease liabilities	Current operating lease liabilities	6
Non-current operating lease liabilities	Non-current operating lease liabilities	87

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

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

(1) Includes $1 million of variable lease costs paid to the lessor.

(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 years ended December 31, 2018 and 2017, we recognized rental expense for all operating leases of $16 million and $13 million, respectively.

Future annual minimum lease payments for operating leases as of December 31, 2019 are as follows (in millions):

Years Ending December 31,	Operating Leases
2020	$ 9
2021	10
2022	10
2023	10
2024	10
Thereafter	116
Total lease payments	165
Less: Interest	(72)
Present value of lease liabilities	$ 93

Future annual minimum lease payments for operating leases as of December 31, 2018, prepared in accordance with accounting standards prior to the adoption of ASC 842, were as follows (in millions):

Years Ending December 31,	Operating Leases (1)
2019	$ 10
2020	10
2021	10
2022	10
2023	10
Thereafter	124
Total	$ 174

(1) Includes certain lease option renewals that are reasonably assured and payments for certain non-lease components.

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

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

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

	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	$ 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, 2019, 2018 and 2017 (in millions):

	Year Ended December 31,		
	2019	2018	2017
LNG revenues	$ 5,210	$ 4,828	$ 2,635
LNG revenues—affiliate	1,312	1,299	1,389
Regasification revenues	266	261	260
Other revenues	49	39	20
Total revenues from customers	6,837	6,427	4,304
Net derivative gains (losses) (1)	1	(1)	—
Total revenues	$ 6,838	$ 6,426	$ 4,304

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

LNG Revenues

We have entered into numerous SPAs with third party customers for the sale of LNG on 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 approximately 4 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, 2019, 2018 and 2017, SPL recorded $104 million, $30 million and $23 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,	
	2019	2018
Deferred revenues, beginning of period	$ 116	$ 111
Cash received but not yet recognized	155	116
Revenue recognized from prior period deferral	(116)	(111)
Deferred revenues, end of period	$ 155	$ 116

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, 2019 and 2018 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, 2019 and 2018:

	December 31, 2019		December 31, 2018	
	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)
LNG revenues (2)	$ 55.0	10	$ 53.6	10
Regasification revenues	2.4	5	2.6	6
Total revenues	$ 57.4		$ 56.2	

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

(2) Includes future consideration from agreement contractually assigned to SPL from Cheniere Marketing.

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 52% and 57% of our LNG revenues during the years ended December 31, 2019 and 2018, respectively, were related to variable consideration received from customers. During each of the years ended December 31, 2019 and 2018, approximately 3% of our regasification revenues were related to variable consideration received from customers. All of our LNG revenues—affiliate were related to variable consideration received from customers during each of the years ended December 31, 2019 and 2018.

We have entered 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, 2019, 2018 and 2017 (in millions):

	Year Ended December 31,		
	2019	2018	2017
LNG revenues—affiliate			
Cheniere Marketing Agreements	$ 1,309	$ 1,299	$ 1,389
Contracts for Sale and Purchase of Natural Gas and LNG	3	—	—
Total LNG revenues—affiliate	1,312	1,299	1,389
Cost of sales—affiliate			
Contracts for Sale and Purchase of Natural Gas and LNG	7	—	—
Operating and maintenance expense—affiliate			
Services Agreements	138	117	94
Other agreements	—	—	6
Total operating and maintenance expense—affiliate	138	117	100
General and administrative expense—affiliate			
Services Agreements	102	73	80
Other income—affiliate			
Cooperative Endeavor Agreement	2	—	—

As of December 31, 2019 and 2018, we had $105 million and $114 million, respectively, of accounts receivable—affiliate, under the agreements described below.

Terminal Use Agreement

SPL obtained approximately 2 Bcf/d of regasification capacity and other liquefaction support services under a TUA with SPLNG as a result of an assignment in July 2012 by Cheniere Investments of its rights, title and interest under its TUA with SPLNG. SPL is obligated to make monthly capacity payments to SPLNG aggregating approximately $250 million per year (the "TUA Fees"), continuing until at least May 2036.

In connection with this TUA, SPL is required to pay for a portion of the cost (primarily LNG inventory) to maintain the cryogenic readiness of the regasification facilities at the Sabine Pass LNG terminal, which is recorded as operating and maintenance expense on our Consolidated Statements of Income.

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 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.

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

Services Agreements

As of December 31, 2019 and 2018, we had $158 million and $228 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.

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 $3 million in due to affiliates and $20 million and $22 million of other non-current liabilities—affiliate resulting from these payments received from Cheniere Marketing as of December 31, 2019 and 2018, 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 \$8 million, \$6 million and \$3 million during the years ended December 31, 2019, 2018 and 2017, 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, 2019, 2018 and 2017.

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 (LOSS) PER COMMON UNIT

Net income (loss) 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 (loss) 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 28, 2020, we declared a \$0.63 distribution per common unit and subordinated unit and the related distribution to our general partner and IDR holders to be paid on February 14, 2020 to unitholders of record as of February 7, 2020 for the period from October 1, 2019 to December 31, 2019.

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 (loss) 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 Class B units, which were mandatorily converted into our common units in accordance with the terms of our partnership agreement on August 2, 2017, were issued at a discount to the market price of the common units into which they were convertible. This discount, totaling $2,130 million, represented a beneficial conversion feature and was reflected as an increase in common and subordinated unitholders' equity and a decrease in Class B unitholders' equity to reflect the fair value of the Class B units at issuance on our Consolidated Statement of Partners' Equity. The beneficial conversion feature was considered a dividend that was distributed ratably with respect to any Class B unit from its issuance date through its conversion date, which resulted in an increase in Class B unitholders' equity and a decrease in common and subordinated unitholders' equity. We amortized the beneficial conversion feature through the mandatory conversion date of August 2, 2017 using the effective yield method, with a weighted average effective yield of 888.7% per year and 966.1% per year for Class B units previously held by Cheniere Energy Partners LP Holdings, LLC and Blackstone CQP Holdco, respectively. The impact of the beneficial conversion feature was also included in earnings per unit for the year ended December 31, 2017.

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 (loss) per unit (in millions, except per unit data).

		Limited Partner Units				
	Total	Common Units	Class B Units	Subordinated Units	General Partner Units	IDR
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		
Year Ended December 31, 2017						
Net income	$ 490					
Declared distributions	514	376	—	127	10	1
Amortization of beneficial conversion feature of Class B units	—	(594)	2,004	(1,410)	—	—
Assumed allocation of undistributed net loss	$ (24)	(17)	—	(7)	—	—
Assumed allocation of net income		$ (235)	$ 2,004	$ (1,290)	$ 10	$ 1
Weighted average units outstanding		178.5	84.8	135.4		
Basic and diluted net loss per unit (2)		$ (1.32)		$ (9.52)		

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

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

NOTE 16—COMMITMENTS AND CONTINGENCIES

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, 2019, 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, 2019, and including estimated costs for an optional third marine berth. As of December 31, 2019, we have incurred $1.1 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, 2019, SPL has secured up to approximately 3,850 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, 2019, 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)
2020	$ 2,248
2021	1,334
2022	849
2023	640
2024	320
Thereafter	1,914
Total	$ 7,305

(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, 2019. 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, 2019, our restricted net assets of consolidated subsidiaries were approximately $3.0 billion.

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, 2019, 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 balances of 10% or greater of total accounts receivable from external customers:

	Percentage of Total Revenues from External Customers			Percentage of Accounts Receivable from External Customers	
	Year Ended December 31,			December 31,	
	2019	2018	2017	2019	2018
Customer A	27%	28%	39%	21%	35%
Customer B	18%	21%	27%	13%	23%
Customer C	19%	23%	23%	22%	30%
Customer D	20%	19%	—%	13%	8%
Customer E	*	—%	—%	13%	—%
Customer F	*	*	*	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,		
	2019	2018	2017
United States	$ 2,354	$ 1,880	$ 1,441
India	1,113	981	—
South Korea	1,071	1,168	666
Ireland	988	1,098	787
Other countries	—	—	21
Total	$ 5,526	$ 5,127	$ 2,915

NOTE 18—SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2019	2018	2017
Cash paid during the period for interest, net of amounts capitalized	$ 829	$ 719	$ 510

The balance in property, plant and equipment, net funded with accounts payable and accrued liabilities (including affiliate) was $291 million, $263 million and $273 million as of December 31, 2019, 2018 and 2017, respectively.

NOTE 19—SUPPLEMENTAL GUARANTOR INFORMATION

Our CQP Senior Notes are jointly and severally guaranteed by each of our subsidiaries other than SPL (the “Guarantors”) and, subject to certain conditions governing its guarantee, Sabine Pass LP (collectively with SPL, the “Non-Guarantors”). These guarantees are full and unconditional, subject to certain customary release provisions including (1) the sale, exchange, disposition or transfer (by merger, consolidation or otherwise) of the capital stock or all or substantially all of the assets of the 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. See Note 11—Debt for additional information regarding the CQP Senior Notes.

The following is condensed consolidating financial information for Cheniere Partners (“Parent Issuer”), the Guarantors on a combined basis and the Non-Guarantors on a combined basis. The condensed consolidating financial information has been prepared using the same accounting policies as described in Note 3—Summary of Significant Accounting Policies, except for the investments in subsidiaries, which is accounted for using the equity method.

In lieu of Schedule I pursuant to the requirements of Rule 5-04 of Reg S-X, the condensed parent company financial statements are presented below in the Parent Issuer column. The condensed parent only financial statements have been provided in accordance with the rules and regulations of the SEC and should be read in conjunction with Cheniere Partners' Consolidated Financial Statements. Pursuant to the SEC rules and regulations, the condensed parent company financial statements do not include all of the financial information and notes normally included with financial statements prepared in accordance with GAAP.

Condensed Consolidating Balance Sheet
December 31, 2019
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
ASSETS					
Current assets					
Cash and cash equivalents	$ 1,778	$ 3	$ —	$ —	$ 1,781
Restricted cash	—	—	181	—	181
Accounts and other receivables	—	5	292	—	297
Accounts receivable—affiliate	—	43	104	(42)	105
Advances to affiliate	—	145	133	(120)	158
Inventory	—	13	103	—	116
Derivative assets	—	—	17	—	17
Other current assets	—	15	36	—	51
Other current assets—affiliate	—	1	22	(22)	1
Total current assets	1,778	225	888	(184)	2,707
Property, plant and equipment, net	79	2,454	13,861	(26)	16,368
Operating lease assets, net	—	88	21	(15)	94
Debt issuance costs, net	9	—	6	—	15
Non-current derivative assets	—	—	32	—	32
Investments in subsidiaries	2,963	508	—	(3,471)	—
Other non-current assets, net	—	24	144	—	168
Total assets	$ 4,829	$ 3,299	$ 14,952	$ (3,696)	$ 19,384
LIABILITIES AND PARTNERS' EQUITY					
Current liabilities					
Accounts payable	$ —	$ 2	$ 38	$ —	$ 40
Accrued liabilities	56	24	629	—	709
Due to affiliates	3	155	49	(161)	46
Deferred revenue	—	23	132	—	155
Deferred revenue—affiliate	—	22	—	(21)	1
Current operating lease liabilities	—	6	—	—	6
Derivative liabilities	—	—	9	—	9
Total current liabilities	59	232	857	(182)	966
Long-term debt, net	4,055	—	13,524	—	17,579
Non-current operating lease liabilities	—	82	5	—	87
Non-current derivative liabilities	—	—	16	—	16
Other non-current liabilities	—	1	—	—	1
Other non-current liabilities—affiliate	—	21	16	(17)	20
Partners' equity	715	2,963	534	(3,497)	715
Total liabilities and partners' equity	$ 4,829	$ 3,299	$ 14,952	$ (3,696)	$ 19,384

Condensed Consolidating Balance Sheet
December 31, 2018
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
ASSETS					
Current assets					
Cash and cash equivalents	$ —	$ —	$ —	$ —	$ —
Restricted cash	779	6	756	—	1,541
Accounts and other receivables	1	1	346	—	348
Accounts receivable—affiliate	1	40	113	(40)	114
Advances to affiliate	—	104	210	(86)	228
Inventory	—	12	87	—	99
Derivative assets	—	—	6	—	6
Other current assets	—	2	18	—	20
Other current assets—affiliate	—	—	21	(21)	—
Total current assets	781	165	1,557	(147)	2,356
Property, plant and equipment, net	79	2,128	13,209	(26)	15,390
Debt issuance costs, net	1	—	12	—	13
Non-current derivative assets	—	—	31	—	31
Investments in subsidiaries	2,544	440	—	(2,984)	—
Other non-current assets, net	—	26	158	—	184
Total assets	$ 3,405	$ 2,759	$ 14,967	$ (3,157)	$ 17,974
LIABILITIES AND PARTNERS' EQUITY					
Current liabilities					
Accounts payable	$ —	$ 4	$ 11	$ —	$ 15
Accrued liabilities	39	14	768	—	821
Due to affiliates	—	127	48	(126)	49
Deferred revenue	—	25	91	—	116
Deferred revenue—affiliate	—	22	—	(21)	1
Derivative liabilities	—	—	66	—	66
Total current liabilities	39	192	984	(147)	1,068
Long-term debt, net	2,566	—	13,500	—	16,066
Non-current derivative liabilities	—	—	14	—	14
Other non-current liabilities	—	1	3	—	4
Other non-current liabilities—affiliate	—	22	—	—	22
Partners' equity	800	2,544	466	(3,010)	800
Total liabilities and partners' equity	$ 3,405	$ 2,759	$ 14,967	$ (3,157)	$ 17,974

Condensed Consolidating Statement of Income
Year Ended December 31, 2019
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Revenues					
LNG revenues	$ —	$ —	$ 5,211	$ —	$ 5,211
LNG revenues—affiliate	—	—	1,312	—	1,312
Regasification revenues	—	266	—	—	266
Regasification revenues—affiliate	—	262	—	(262)	—
Other revenues	—	49	—	—	49
Other revenues—affiliate	—	137	—	(137)	—
Total revenues	—	714	6,523	(399)	6,838
Operating costs and expenses					
Cost of sales (excluding depreciation and amortization expense shown separately below)	—	1	3,373	—	3,374
Cost of sales—affiliate	—	7	47	(47)	7
Operating and maintenance expense	—	85	547	—	632
Operating and maintenance expense—affiliate	—	30	450	(342)	138
General and administrative expense	3	2	6	—	11
General and administrative expense—affiliate	13	27	79	(17)	102
Depreciation and amortization expense	3	78	447	(1)	527
Impairment expense and loss on disposal of assets	—	1	6	—	7
Total operating costs and expenses	19	231	4,955	(407)	4,798
Income (loss) from operations	(19)	483	1,568	8	2,040
Other income (expense)					
Interest expense, net of capitalized interest	(174)	(6)	(705)	—	(885)
Loss on modification or extinguishment of debt	(13)	—	—	—	(13)
Equity earnings of subsidiaries	1,360	873	—	(2,233)	—
Other income	21	—	10	—	31
Other income—affiliate	—	2	—	—	2
Total other income (expense)	1,194	869	(695)	(2,233)	(865)
Net income	$ 1,175	$ 1,352	$ 873	$ (2,225)	$ 1,175

Condensed Consolidating Statement of Income
Year Ended December 31, 2018
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Revenues					
LNG revenues	$ —	$ —	$ 4,827	$ —	$ 4,827
LNG revenues—affiliate	—	—	1,299	—	1,299
Regasification revenues	—	261	—	—	261
Regasification revenues—affiliate	—	258	—	(258)	—
Other revenues	—	39	—	—	39
Other revenues—affiliate	—	247	—	(247)	—
Total revenues	—	805	6,126	(505)	6,426
Operating costs and expenses					
Cost of sales (excluding depreciation and amortization expense shown separately below)	—	—	3,403	—	3,403
Cost of sales—affiliate	—	—	32	(32)	—
Operating and maintenance expense	—	67	342	—	409
Operating and maintenance expense—affiliate	—	151	423	(457)	117
Development expense	—	—	2	—	2
General and administrative expense	4	2	5	—	11
General and administrative expense—affiliate	12	25	50	(14)	73
Depreciation and amortization expense	2	74	349	(1)	424
Impairment expense and loss on disposal of assets	—	8	—	—	8
Total operating costs and expenses	18	327	4,606	(504)	4,447
Income (loss) from operations	(18)	478	1,520	(1)	1,979
Other income (expense)					
Interest expense, net of capitalized interest	(139)	(5)	(589)	—	(733)
Loss on modification or early extinguishment of debt	(12)	—	—	—	(12)
Derivative gain, net	14	—	—	—	14
Equity earnings of subsidiaries	1,416	944	—	(2,360)	—
Other income	13	—	13	—	26
Total other income (expense)	1,292	939	(576)	(2,360)	(705)
Net income	$ 1,274	$ 1,417	$ 944	$ (2,361)	$ 1,274

Condensed Consolidating Statement of Income
Year Ended December 31, 2017
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Revenues					
LNG revenues	$ —	$ —	$ 2,635	$ —	$ 2,635
LNG revenues—affiliate	—	—	1,389	—	1,389
Regasification revenues	—	260	—	—	260
Regasification revenues—affiliate	—	190	—	(190)	—
Other revenues	—	20	—	—	20
Other revenues—affiliate	—	218	—	(218)	—
Total revenues	—	688	4,024	(408)	4,304
Operating costs and expenses					
Cost of sales (excluding depreciation and amortization expense shown separately below)	—	1	2,317	2	2,320
Cost of sales—affiliate	—	—	23	(23)	—
Operating and maintenance expense	4	45	243	—	292
Operating and maintenance expense—affiliate	6	137	329	(372)	100
Development expense	—	1	2	—	3
General and administrative expense	4	1	7	—	12
General and administrative expense—affiliate	11	15	58	(4)	80
Depreciation and amortization expense	2	74	264	(1)	339
Impairment expense and loss on disposal of assets	—	2	—	—	2
Total operating costs and expenses	27	276	3,243	(398)	3,148
Income (loss) from operations	(27)	412	781	(10)	1,156
Other income (expense)					
Interest expense, net of capitalized interest	(111)	(9)	(494)	—	(614)
Loss on modification or early extinguishment of debt	(25)	—	(42)	—	(67)
Derivative gain (loss), net	6	—	(2)	—	4
Equity earnings of subsidiaries	643	250	—	(893)	—
Other income	4	—	7	—	11
Total other income (expense)	517	241	(531)	(893)	(666)
Net income	$ 490	$ 653	$ 250	$ (903)	$ 490

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2019
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Cash flows provided by operating activities	$ 1,220	$ 1,403	$ 1,161	$ (2,237)	$ 1,547
Cash flows from investing activities					
Property, plant and equipment, net	(2)	(49)	(1,282)	2	(1,331)
Investments in subsidiaries	(1,273)	(1,046)	—	2,319	—
Return of capital	853	626	—	(1,479)	—
Other	—	—	(1)	—	(1)
Net cash used in investing activities	(422)	(469)	(1,283)	842	(1,332)
Cash flows from financing activities					
Proceeds from issuances of debt	2,230	—	—	—	2,230
Repayments of debt	(730)	—	—	—	(730)
Debt issuance and deferred financing costs	(35)	—	—	—	(35)
Distributions to parent	—	(2,215)	(1,499)	3,714	—
Contributions from parent	—	1,273	1,046	(2,319)	—
Distributions to owners	(1,260)	—	—	—	(1,260)
Other	(4)	5	—	—	1
Net cash provided by (used in) financing activities	201	(937)	(453)	1,395	206
Net increase (decrease) in cash, cash equivalents and restricted cash	999	(3)	(575)	—	421
Cash, cash equivalents and restricted cash—beginning of period	779	6	756	—	1,541
Cash, cash equivalents and restricted cash—end of period	$ 1,778	$ 3	$ 181	$ —	$ 1,962

Balances per Condensed Consolidating Balance Sheet:

	December 31, 2019				
	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Cash and cash equivalents	$ 1,778	$ 3	$ —	$ —	$ 1,781
Restricted cash	—	—	181	—	181
Total cash, cash equivalents and restricted cash	$ 1,778	$ 3	$ 181	$ —	$ 1,962

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2018
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Cash flows provided by operating activities	$ 714	$ 569	$ 1,423	$ (832)	$ 1,874
Cash flows from investing activities					
Property, plant and equipment, net	—	(34)	(771)	1	(804)
Investments in subsidiaries	(304)	(129)	—	433	—
Distributions received from affiliates, net	454	537	—	(991)	—
Net cash provided by (used in) investing activities	150	374	(771)	(557)	(804)
Cash flows from financing activities					
Proceeds from issuances of debt	1,100	—	—	—	1,100
Repayments of debt	(1,090)	—	—	—	(1,090)
Debt issuance and deferred financing costs	(8)	—	—	—	(8)
Debt extinguishment costs	(7)	—	—	—	(7)
Distributions to parent	—	(1,253)	(569)	1,822	—
Contributions from parent	—	304	129	(433)	—
Distributions to owners	(1,113)	—	—	—	(1,113)
Net cash used in financing activities	(1,118)	(949)	(440)	1,389	(1,118)
Net increase (decrease) in cash, cash equivalents and restricted cash	(254)	(6)	212	—	(48)
Cash, cash equivalents and restricted cash—beginning of period	1,033	12	544	—	1,589
Cash, cash equivalents and restricted cash—end of period	$ 779	$ 6	$ 756	$ —	$ 1,541

	December 31, 2018				
	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Cash and cash equivalents	$ —	$ —	$ —	$ —	$ —
Restricted cash	779	6	756	—	1,541
Total cash, cash equivalents and restricted cash	$ 779	$ 6	$ 756	$ —	$ 1,541

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2017
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Cash flows provided by (used in) operating activities	$ (101)	$ 431	$ 657	$ (10)	$ 977
Cash flows from investing activities					
Property, plant and equipment, net	—	(21)	(1,279)	10	(1,290)
Investments in subsidiaries	(245)	(7)	—	252	—
Distributions received from affiliates, net	1,431	782	—	(2,213)	—
Net cash provided by (used in) investing activities	1,186	754	(1,279)	(1,951)	(1,290)
Cash flows from financing activities					
Proceeds from issuances of debt	1,500	—	2,314	—	3,814
Repayments of debt	(1,470)	—	(703)	—	(2,173)
Debt issuance and deferred financing costs	(22)	—	(28)	—	(50)
Distributions to parent	—	(1,431)	(782)	2,213	—
Contributions from parent	—	245	7	(252)	—
Distributions to owners	(294)	—	—	—	(294)
Net cash provided by (used in) financing activities	(286)	(1,186)	808	1,961	1,297
Net increase (decrease) in cash, cash equivalents and restricted cash	799	(1)	186	—	984
Cash, cash equivalents and restricted cash—beginning of period	234	13	358	—	605
Cash, cash equivalents and restricted cash—end of period	$ 1,033	$ 12	$ 544	$ —	$ 1,589

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, 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
Year ended December 31, 2018:				
Revenues	$ 1,593	$ 1,407	$ 1,529	$ 1,897
Income from operations	508	455	492	524
Net income	335	281	307	351
Net income per common unit—basic and diluted (1)	0.67	0.55	0.60	0.69

(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, 2019, 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 on page 57 and is incorporated herein by reference.

ITEM 9B. OTHER INFORMATION

None.

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 John-Paul Munfa, 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, 2020, regarding the individuals who currently serve on the board of directors and as executive officers of our general partner. The appointments of Messrs. Meier, Munfa and Welch 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	57	May 2016	Chairman of the Board and President and Chief Executive Officer
Michael J. Wortley	43	January 2014	Director and Executive Vice President and Chief Financial Officer
Eric Bensaude	53	September 2016	Director
Aaron Stephenson	64	November 2019	Director and Senior Vice President, Operations
Philip Meier	61	July 2013	Director
John-Paul Munfa	38	February 2015	Director
Jamie Welch	53	August 2017	Director
James R. Ball	69	September 2012	Director
Lon McCain	72	March 2007	Director
Vincent Pagano, Jr.	69	December 2012	Director
Oliver G. Richard, III	67	September 2012	Director

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.

Michael J. Wortley

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

Mr. Wortley has served as Chief Financial Officer of Cheniere since January 2014 and as Executive Vice President of Cheniere since September 2016. Mr. Wortley served as Senior Vice President of Cheniere from January 2014 to September 2016. Mr. Wortley also served as a director and Chief Financial Officer of Cheniere Holdings from January 2014 to September 2018 and Executive Vice President from September 2016 to September 2018. Mr. Wortley served as Vice President–Strategy and Risk of Cheniere from January 2013 to January 2014 and as Vice President–Business Development of Cheniere and President of Corpus Christi Liquefaction, LLC, a wholly owned subsidiary of Cheniere, from September 2011 to January 2013. Mr. Wortley served as Cheniere's Vice President–Strategic Planning from January 2009 to September 2011 and Manager–Strategic New Business from August 2007 to January 2009. Mr. Wortley is also Chief Financial Officer of the general partner of SPLNG and a manager and Chief Financial Officer of SPL. Prior to joining Cheniere in February 2005, Mr. Wortley spent five years in oil and gas corporate development, mergers, acquisitions and divestitures with Anadarko Petroleum Corporation ("Anadarko"), a publicly traded oil and gas exploration and production company. Mr. Wortley began his career with Union Pacific Resources Corporation, a publicly traded oil and gas exploration and production company subsequently acquired by Anadarko. Mr. Wortley received a B.B.A. in Finance from Southern Methodist University. It was determined that Mr. Wortley should serve as a director of our general partner because of his financial expertise and his perspective as Chief Financial Officer of Cheniere and certain of its affiliates. Other than Cheniere Holdings, Mr. Wortley 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.

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.

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

Mr. Meier is president of Meier Consulting LLC and is currently providing technical and project management advice to Blackstone CQP Holdco with respect to the Liquefaction Project. From 2007 to 2012, Mr. Meier was Senior Vice President Projects with Woodside Energy, an oil and gas company in Perth, Western Australia, where he was accountable for delivery of all Woodside construction projects (both LNG and offshore). Prior to this, he spent 25 years with Bechtel at various levels culminating as Project Manager of Egyptian LNG Train 2. Mr. Meier received a BSCE from Rensselaer Polytechnic Institute and an M.B.A. in Finance and International Business from the University of Houston. It was determined that Mr. Meier should serve as a director of our general partner because of his international experience and expertise in the LNG industry. Mr. Meier has not held any other directorship positions in the past five years.

John-Paul Munfa
Director of our general partner and a member of the CMI SPA Committee and the Executive Committee

Mr. Munfa is a Managing Director in the Private Equity Group of Blackstone Group, an investment and advisory firm. Mr. Munfa joined Blackstone Group in 2004 and was an employee in its Restructuring & Reorganization and Private Equity Groups from 2004 to 2009. Mr. Munfa re-joined Blackstone Group in 2011 after receiving an M.B.A. from Stanford University's Graduate School of Business. Mr. Munfa also received an A.B. in Economics from Harvard University. It was determined that Mr. Munfa should serve as a director of our general partner because of his significant investment experience with Blackstone Group. Mr. Munfa has not held any other directorship positions in the past five years.

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

Mr. Welch currently serves as the President and Chief Financial Officer of EagleClaw Midstream Ventures LLC. Mr. Welch was the Group Chief Financial Officer and Head of Business Development for the Energy Transfer Equity, L.P. ("ETE") family from June 2013 to February 2016. Mr. Welch also served on the Board of Directors of ETE, Energy Transfer Partners and Sunoco Logistics from June 2013 to February 2016. Before joining ETE, Mr. Welch was Head of the EMEA Investment Banking Department and Head of the Global Energy Group at Credit Suisse. He was also a member of the Investment Banking Division Global Management Committee and the EMEA Operating Committee. Mr. Welch joined Credit Suisse First Boston in 1997 from Lehman Brothers Inc. in New York, where he was a Senior Vice President in the global utilities and project finance group. Prior to that he was an attorney with Milbank, Tweed, Hadley & McCloy (New York) and a barrister and solicitor with Minter Ellison in Melbourne, Australia. It was determined that Mr. Welch should serve as a director of our general partner because of his understanding of energy-related corporate finance gained through his experience in the investment banking and legal fields.

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.

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 into which Crimson Exploration, Inc. was merged effective October 2, 2013. Mr. McCain served on the Board of Crimson Exploration, Inc. from 2005 until the merger with Contango. 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.

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 currently also serves as a director of Hovnanian Enterprises, Inc., a publicly traded homebuilding company. Mr. Pagano previously served as a director of L3 Technologies, Inc. (formerly known as L-3 Communications Holdings, Inc.), a publicly traded defense company, from April 2013 to June 2019. 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. It was determined that Mr. Pagano should serve as a director of our general partner because of his capital markets expertise and his experience as an advisor to public companies on a variety of corporate matters.

Oliver G. Richard, III
Director of our general partner and a member of the Audit Committee and Conflicts Committee

Mr. Richard is the owner and president of Empire of the Seed, LLC, a private consulting firm in the energy and management industries. Mr. Richard served as Chairman, President and Chief Executive Officer of Columbia Energy Group, a natural gas company, from 1995 until 2000, and as a director of Buckeye Partners, L.P., a publicly traded petroleum product pipeline and terminal company, from 2009 through its acquisition in 2019. Mr. Richard was a Commissioner on the FERC from 1982 until 1985. Mr. Richard currently serves as a director of American Electric Power Company, Inc., a publicly traded electric utility. Mr. Richard received a B.S. in Journalism, a J.D. from Louisiana State University and a Master of Law in Taxation from Georgetown

University. It was determined that Mr. Richard should serve as a director of our general partner because of his extensive background in the energy industry, including his experience in both the public and private sectors of the energy industry.

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
Michael J. Wortley
Eric Bensaude
Aaron Stephenson
Philip Meier
John-Paul Munfa
Jamie Welch
James R. Ball
Lon McCain
Vincent Pagano, Jr.
Oliver G. Richard, III

Compensation Committee Interlocks and Insider Participation

As discussed above, the board of directors of our general partner does not have a compensation committee. If any compensation is to be paid to our general partners' officers, the compensation would be reviewed and approved by the entire board of directors of our general partner because they perform the functions of a compensation committee in the event such committee is needed. None of the directors or executive officers of our general partner served as a member of a compensation committee of another entity that has or has had an executive officer who served as a member of the board of directors of our general partner during 2019.

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. Welch serves as Senior Advisor of Blackstone Group and Mr. Munfa serves as a Managing Director in the Private Equity Group of Blackstone Group, and they do not receive additional compensation for service as directors. Mr. 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 receives 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 2019 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)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Michael J. Wortley (2)	—	—	—	—	—	—	—
Eric Bensaude (2)	—	—	—	—	—	—	—
Doug Shanda (2)	—	—	—	—	—	—	—
Aaron Stephenson (2)	—	—	—	—	—	—	—
Philip Meier (3)	—	—	—	—	—	—	—
John-Paul Munfa (4)	—	—	—	—	—	—	—
Jamie Welch (4)	—	—	—	—	—	—	—
James R. Ball (5)	132,500	132,000	—	—	—	—	264,500
Lon McCain (6)	122,500	122,070	—	—	—	—	244,570
Vincent Pagano, Jr. (7)	117,500	117,360	—	—	—	—	234,860
Oliver G. Richard, III (8)	107,500	132,000	—	—	—	—	239,500

(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 2019. Mr. Wortley served as an executive officer of our general partner and as an executive officer of Cheniere during fiscal year 2019. Mr. Bensaude served as an officer of Cheniere Marketing Ltd., a subsidiary of Cheniere during fiscal year 2019. Mr. Shanda served as an officer of our general partner and as an executive officer of Cheniere from January 1 until November 1, 2019. Mr. Stephenson has served as an officer of our general partner and as an executive officer of Cheniere since November 1, 2019. 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. Meier is 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.

(4) Mr. Munfa is a Managing Director in the Private Equity Group of Blackstone Group and Mr. Welch serves as Senior Advisor to Blackstone Group. They do not receive additional compensation for service as directors.

(5) Mr. Ball was granted 3,000 phantom units in 2019 with a grant date fair value of $132,000. In addition, Mr. Ball received $49,500 in cash and 1,875 common units on account of 3,000 phantom units granted in earlier years that vested in 2019. As of December 31, 2019, he held 7,500 phantom units and 11,250 common units for a total of 18,750 units.

(6) Mr. McCain was granted 3,000 phantom units in 2019 with a grant date fair value of $122,070. In addition, Mr. McCain received $61,035 in cash and 1,500 common units on account of 3,000 phantom units granted in earlier years that vested in 2019. As of December 31, 2019, he held 7,500 phantom units and 6,750 common units for a total of 14,250 units.

(7) Mr. Pagano was granted 3,000 phantom units in 2019 with a grant date fair value of $117,360. In addition, Mr. Pagano received $58,680 in cash and 1,500 common units on account of 3,000 phantom units granted in earlier years that vested in 2019. As of December 31, 2019, he held 7,500 phantom units and 5,625 common units for a total of 13,125 units.

(8) Mr. Richard was granted 3,000 phantom units in 2019 with a grant date fair value of $132,000. In addition, Mr. Richard received $33,000 in cash and 2,250 common units on account of 3,000 phantom units granted in earlier years that vested in 2019. As of December 31, 2019, he held 7,500 phantom units and 9,375 common units for a total of 16,875 units.

Indemnification of Directors

We have entered into indemnification agreements with each of our directors, which provide for indemnification with respect to all expenses and claims that a director incurs as a result of actions taken, or not taken, on our behalf while serving as a director, officer, employee, controlling person, 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, 2020, the following units were outstanding: 348.6 million common units and 135.4 million subordinated units. In addition, as of February 19, 2020, there were 9.9 million general partner units outstanding.

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, subordinated units and/or general partner units as of February 19, 2020:

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Securities Beneficially Owned
Cheniere Energy, Inc. (1)	104,488,671	30%	135,383,831	100%	51%
Blackstone Group (2)	4,382,079	1%	—	—	1%
Blackstone CQP Holdco (2)	198,978,886	57%	—	—	40%

(1) Cheniere Energy, Inc. also owns 9,877,546 of our general partner units.

(2) Information is based on the Schedule 13D/A filed with the SEC on August 11, 2017 by the Blackstone Group, L.P., Blackstone CQP Common Holdco L.P., Blackstone CQP Common Holdco GP LLC, Blackstone Energy Management Associates L.L.C., Blackstone EMA L.L.C., Blackstone Management Associates VI L.L.C., BMA VI L.L.C., Blackstone Holdings III L.P., Blackstone Holdings III GP L.P., Blackstone Holdings III GP Management L.L.C., GSO Credit Alpha Fund AIV-2 LP, GSO Coastline Credit Partners LP, GSO Credit-A Partners LP, GSO Palmetto Opportunistic Investment Partners LP, GSO Special Situations Fund LP, GSO Special Situations Master Fund LP, GSO Special Situations Overseas Master Fund Ltd., Blackstone Holdings I L.P., Blackstone Holdings II L.P., Blackstone Holdings I/II GP Inc., GSO Capital Partners LP, GSO Advisor

Holdings LLC, GSO Palmetto Opportunistic Associates LLC, GSO Credit-A Associates LLC, GSO Holdings I L.L.C., Blackstone Group Management L.L.C., Stephen A. Schwarzman, Bennett J. Goodman and J. Albert Smith III and a Form 4 filed with the SEC on January 2, 2018 by the Blackstone Group, L.P. Blackstone CQP Common Holdco L.P. is the record holder of 2,011,447 common units. GSO Credit-A Partners LP and GSO Palmetto Opportunistic Investment Partners LP are the record holders of 953,855 and 953,855 common units, respectively. GSO Credit Alpha Fund AIV-2 LP is the record owner of 462,922 common units. Blackstone CQP Holdco is the record holder of 198,978,886 common units. The address of the various persons identified in this footnote is 345 Park Avenue, New York, New York 10154.

Directors and Executive Officers

The following table sets forth information with respect to our common units beneficially owned as of February 19, 2020, 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, 2020, the current directors and executive officers of Cheniere Partners beneficially owned an aggregate of 41,788 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, 2020, 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, 2020, Cheniere Energy, Inc. had 254.1 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)	—	—%	703,814 (1)	*%
Michael J. Wortley	—	—	551,798	*
Eric Bensaude	—	—	—	—
Doug Shanda	2,850	*	148,445	*
Aaron Stephenson	—	—	—	—
Philip Meier (2)	—	—	—	—
John-Paul Munfa (2)	—	—	—	—
Jamie Welch (2)	8,788	*	—	—
James R. Ball	11,250	*	—	—
Lon McCain	6,750	*	—	—
Vincent Pagano, Jr.	5,625	*	—	—
Oliver G. Richard, III	9,375	*	—	—
All current directors and executive officers as a group (11 persons) (3)	41,788	*%	1,255,612	*%

* Less than 1%

(1) Includes 177,778 shares held by trust.

(2) Messrs. Meier, Munfa and Welch 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.

(3) Excludes shares owned by Mr. Shanda, who was no longer an executive officer of the Company on February 19, 2020.

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, 2019 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	15,375	N/A	1,203,125
Total	15,375	N/A	1,203,125

(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, 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, which were $416,667 and $375,000, respectively, in 2019. Blackstone CQP Holdco also paid Mr. Meier $1,522,850 upon the substantial completion of Train 5 of the Liquefaction Project. The consulting arrangement between Blackstone CQP Holdco and Mr. Meier may be terminated by Blackstone for cause or by either party upon 30 days' advance written notice.

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 2019 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, 2019 and 2018. The following table sets forth the fees paid to KPMG LLP for professional services rendered for 2019 and 2018 (in millions):

	Fiscal 2019	Fiscal 2018
Audit Fees	$ 3	$ 3

Audit Fees—Audit fees for 2019 and 2018 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 2019 and 2018.

Tax Fees—There were no tax fees in 2019 and 2018.

Other Fees—There were no other fees in 2019 and 2018.

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, 2019 and 2018 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.:

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(2) Financial Statement Schedules:

All financial statement schedules have been omitted because they are not required, are not applicable, or the required information has been included elsewhere within this Form 10-K.

(3) Exhibits:

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

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

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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	**Form**	**Exhibit**	**Filing Date**
2.1	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	Form of 5.625% Senior Secured Note due 2021 (Included as Exhibit A-1 to Exhibit 4.2 above)	Cheniere Partners	8-K	4.1	2/4/2013
4.4	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
4.5	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
4.6	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.5 above)	Cheniere Partners	8-K	4.1.2	4/16/2013
4.7	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
4.8	Form of 6.25% Senior Secured Note due 2022 (Included as Exhibit A-1 to Exhibit 4.7 above)	Cheniere Partners	8-K	4.1	11/25/2013
4.9	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
4.10	Form of 5.750% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.9 above)	Cheniere Partners	8-K	4.1	5/22/2014
4.11	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
4.12	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.11 above)	Cheniere Partners	8-K	4.2	5/22/2014
4.13	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
4.14	Form of 5.625% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.13 above)	Cheniere Partners	8-K	4.1	3/3/2015
4.15	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
4.16	Form of 5.875% Senior Secured Note due 2026 (Included as Exhibit A-1 to Exhibit 4.15 above)	Cheniere Partners	8-K	4.1	6/14/2016
4.17	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
4.18	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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
4.19	Form of 5.00% Senior Secured Note due 2027 (Included as Exhibit A-1 to Exhibit 4.18 above)	Cheniere Partners	8-K	4.2	9/23/2016
4.20	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
4.21	Form of 4.200% Senior Secured Note due 2028 (Included as Exhibit A-1 to Exhibit 4.20 above)	Cheniere Partners	8-K	4.1	3/6/2017
4.22	Indenture, dated as of February 24, 2017, between SPL, the guarantors that may become party thereto from time to time and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere Partners	8-K	4.1	2/27/2017
4.23	Form of 5.00% Senior Secured Note due 2037 (Included as Exhibit A-1 to Exhibit 4.22 above)	Cheniere Partners	8-K	4.1	2/27/2017
4.24	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
4.25	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
4.26	Form of 5.250% Senior Note due 2025 (Included as Exhibit A-1 to Exhibit 4.25 above)	Cheniere Partners	8-K	4.2	9/18/2017
4.27	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
4.28	Form of 5.625% Senior Note due 2026 (Included as Exhibit A-1 to Exhibit 4.27 above)	Cheniere Partners	8-K	4.1	9/12/2018
4.29	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
4.30*	Description of the Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934				
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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.12	Second Amended and Restated LNG Terminal Use Agreement, dated as of July 31, 2012, between SPL and SPLNG	SPLNG	8-K	10.1	8/6/2012
10.13	Letter Agreement, dated May 28, 2013, by and between SPL and SPLNG	SPLNG	10-Q	10.1	8/2/2013
10.14	Guarantee Agreement, dated as of July 31, 2012, by the Partnership in favor of SPLNG	SPLNG	8-K	10.2	8/6/2012
10.15	Second Amended and Restated Common Terms Agreement, dated as of June 30, 2015, among SPL, as Borrower, the representatives and agents from time to time parties thereto, and Société Générale, as the Common Security Trustee and Intercreditor Agent	Cheniere Partners	8-K	10.2	7/1/2015
10.16	Omnibus Amendment, dated as of September 24, 2015, to the Second Amended and Restated Common Terms Agreement among SPL, as Borrower, the representatives and agents from time to time parties thereto, and Société Générale, as the Common Security Trustee and Intercreditor Agent	Cheniere Partners	10-Q	10.6	10/30/2015
10.17	Administrative Amendment to the Second Amended and Restated Common Terms Agreement, dated as of December 31, 2015, among SPL, Société Générale, as the Commercial Banks Facility Agent, The Korea Development Bank, New York Branch, as the KSURE Covered Facility Agent and Shinhan Bank New York Branch, as KEXIM Facility Agent	Cheniere Partners	10-Q	10.7	5/5/2016
10.18	Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, dated September 4, 2015, as amended by (a) Third Omnibus Amendment, dated as of May 23, 2018; (b) Fourth Omnibus Amendment, dated as of September 17, 2018; and (c) Fifth Omnibus Amendment, Consent and Waiver, dated as of May 29, 2019, among SPL, as Borrower, The Bank of Nova Scotia, as Senior Issuing Bank and Senior Facility Agent, ABN Amro Capital USA LLC, HSBC Bank USA, National Association and ING Capital LLC, as Senior Issuing Banks, Société Générale, as Swing Line Lender and Common Security Trustee, and the senior lenders party thereto from time to time	Cheniere Partners	10-Q	10.2	8/8/2019
10.19	Third Omnibus Amendment, dated as of May 23, 2018 to (a) the Second Amended and Restated Common Terms Agreement, dated as of June 30, 2015, by and among SPL, Société Générale, as the Common Security Trustee and as the Intercreditor Agent, The Bank of Nova Scotia, and each other party thereto from time to time and (b) the Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, dated as of September 4, 2015, by and among SPL, Société Générale as the Swing Line Lender and as the Common Security Trustee, The Bank of Nova Scotia as the Senior Issuing Bank and Senior Facility Agent and the other agents and lenders from time to time party thereto	Cheniere Partners (SEC File No. 333-225684)	S-4	10.3	6/15/2018
10.20	Fourth Omnibus Amendment, dated as of September 17, 2018, to (a) the Second Amended and Restated Common Terms Agreement, dated as of June 30, 2015, by and among SPL, as Borrower, Société Générale, as the Common Security Trustee and as the Intercreditor Agent, The Bank of Nova Scotia, as the Secured Debt Holder Group Representative for the Working Capital Debt and other Secured Debt Holder Group Representatives party thereto from time to time, the Secured Hedge Representatives and the Secured Gas Hedge Representatives party thereto from time to time and (b) the Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, dated as of September 4, 2015, by and among SPL, as Borrower, Société Générale as the Swing Line Lender and as the Common Security Trustee, The Bank of Nova Scotia as the Senior Issuing Bank and Senior Facility Agent and the other agents and lenders from time to time party thereto	Cheniere Partners	10-Q	10.1	11/8/2018

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.21*	Fifth Omnibus Amendment, dated as of May 29, 2019, to (a) the Second Amended and Restated Common Terms Agreement, dated as of June 30, 2015, by and among SPL, as Borrower, Société Générale, as the Common Security Trustee and as the Intercreditor Agent, The Bank of Nova Scotia, as the Secured Debt Holder Group Representative for the Working Capital Debt and other Secured Debt Holder Group Representatives party thereto from time to time, the Secured Hedge Representatives and the Secured Gas Hedge Representatives party thereto from time to time and (b) the Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, dated as of September 4, 2015, by and among SPL, as Borrower, Société Générale as the Swing Line Lender and as the Common Security Trustee, The Bank of Nova Scotia as the Senior Issuing Bank and Senior Facility Agent and the other agents and lenders from time to time party thereto				
10.22	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
10.23	Registration Rights Agreement, dated as of September 12, 2019, among the Partnership, the guarantors party thereto and RBC Capital Markets, LLC	Cheniere Partners	8-K	10.1	9/12/2019
10.24†	Cheniere Energy Partners, L.P. 2007 Long-Term Incentive Plan	Cheniere Partners	8-K	10.3	3/26/2007
10.25†	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
10.26†	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
10.27†	Form of Amendment to Phantom Units Agreement	Cheniere Partners	10-Q	10.7	11/2/2012
10.28†	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
10.29†	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
10.30†	Form of Indemnification Agreement for officers and/or directors of Cheniere Partners GP	Cheniere Partners	10-K	10.42	2/19/2016
10.31	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
10.32	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.: 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
10.33	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-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
10.34*	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 Company 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				
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	Letter agreement, dated May 12, 2016, amending the Amended and Restated LNG Sale and Purchase Agreement (FOB) between SPL and BG Gulf Coast LNG, LLC dated January 25, 2012	SPL (SEC File No. 333-215882)	S-4	10.7	2/3/2017
10.42	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
10.43	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
10.44	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
10.45	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
10.46	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
10.47	Letter Agreement regarding the Base SPA, dated May 3, 2019, 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)	Cheniere Partners	10-Q	10.2	5/9/2019
10.48	Letter Agreement regarding the Base SPA, dated December 23, 2019, 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)	Cheniere Partners	8-K	10.1	12/23/2019
10.49	Management Services Agreement, dated May 14, 2012, by and between Cheniere Terminals and SPL	Cheniere Partners	8-K	10.6	5/15/2012
10.50	Amendment to Management Services Agreement, dated September 28, 2015, between Cheniere Terminals and SPL	SPL	10-Q/A	10.8	11/9/2015
10.51	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
10.52	Management Services Agreement, dated May 27, 2013, by and between Cheniere Terminals and CTPL	Cheniere Partners	10-Q	10.2	8/2/2013
10.53	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
10.54	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
10.55	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
10.56	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
10.57	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
10.58	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
10.59	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
10.60	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
10.61	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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.62	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
10.63	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				
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's (SEC File No. 333-138916) reports, as applicable, unless otherwise indicated.

* Filed herewith.

** Furnished herewith.

† Management contract or compensatory plan or arrangement.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

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

CHENIERE ENERGY 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 24, 2020

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 24, 2020
/s/ Michael J. Wortley Michael J. Wortley	Executive Vice President and Chief Financial Officer, Director (Principal Financial Officer)	February 24, 2020
/s/ Leonard E. Travis Leonard E. Travis	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 24, 2020
/s/ Eric Bensaude Eric Bensaude	Director	February 24, 2020
/s/ Aaron Stephenson Aaron Stephenson	Director	February 24, 2020
/s/ Philip Meier Philip Meier	Director	February 24, 2020
/s/ John-Paul R. Munfa John-Paul R. Munfa	Director	February 24, 2020
/s/ Jamie Welch Jamie Welch	Director	February 24, 2020
/s/ James R. Ball James R. Ball	Director	February 24, 2020
/s/ Lon McCain Lon McCain	Director	February 24, 2020
/s/ Vincent Pagano Jr. Vincent Pagano Jr.	Director	February 24, 2020
/s/ Oliver G. Richard, III Oliver G. Richard, III	Director	February 24, 2020

APPENDIX

Adjusted EBITDA

The following table reconciles our Adjusted EBITDA to U.S. GAAP results for 2019 (in millions):

	2019
Net income	$ 1,175
Interest expense, net of capitalized interest	885
Loss on modification or extinguishment of debt	13
Derivative gain, net	—
Other income	(31)
Other income—affiliate	(2)
Income from operations	$ 2,040
Adjustments to reconcile income from operations to Adjusted EBITDA:	
Depreciation and amortization expense	527
Loss (gain) from changes in fair value of commodity derivatives, net	(67)
Impairment expense and loss on disposal of assets	7
Legal settlement expense	—
Adjusted EBITDA	$ 2,507

Board of Directors

Jack A. Fusco
Chairman of the Board and
President and Chief Executive Officer

James R. Ball
Independent Director

Eric Bensaude
Director

Lon McCain
Independent Director

Philip Meier
Director

John-Paul R. Munfa
Director

Vincent Pagano, Jr.
Independent Director

Oliver G. Richard, III
Independent Director

Aaron Stephenson
Director and Senior Vice President, Operations

Jamie Welch
Director

Michael J. Wortley
Director and Executive Vice President and
Chief Financial Officer

Senior Management

Jack A. Fusco
President and Chief Executive Officer

Michael J. Wortley
Executive Vice President and
Chief Financial Officer

Anatol Feygin
Executive Vice President and
Chief Commercial Officer

Tom Bullis
Executive Vice President and
Chief Administrative Officer

Sean N. Markowitz
General Counsel and Corporate Secretary

David Craft
Senior Vice President, Engineering
and Construction

Corey Grindal
Senior Vice President, Gas Supply

Christopher Smith
Senior Vice President, Policy, Government,
and Public Affairs

Aaron Stephenson
Senior Vice President, Operations

Hilary Ware
Chief Human Resources Officer

Officers

Randy Bhatia
Vice President, Investor Relations

Eben Burnham-Snyder
Vice President, Public Affairs

Khary Cauthen
Vice President, Federal Government Affairs

Rina Chang
Vice President, Environmental

Lisa Cohen
Vice President and Treasurer

Zach Davis
Vice President, Finance and Planning

Michael Dove
Vice President and Chief Information Officer

Tony Eaton
Vice President, Project Development
and Engineering

Olivier Herbelot
Chief Risk Officer

William L. Knittle
Vice President, Supply Chain Management

Tom Myers
Vice President, Health and Safety

Julie Nelson
Vice President, State Government Affairs

Deanna L. Newcomb
Chief Compliance and Ethics Officer,
Vice President, Internal Audit

Florian Pintgen
Vice President, Commercial Operations

Mitch Price
Vice President and Chief Security Risk Officer

Len Travis
Vice President and Chief Accounting Officer

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Cheniere Energy Partners, L.P. provides clean, secure, and affordable LNG to the world.
We conduct our business safely and responsibly, delivering a reliable, competitive,
and integrated source of LNG to our customers.

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