Cheniere Energy Partners, L.P.
Form 10-K
February 19, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015
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 No. 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)

Registrant's telephone number, including area code: (713) 375-5000
Securities registered pursuant to Section 12(b) of the Act:

Common Units Representing Limited Partner Interests	NYSE MKT
(Title of Class)	(Name of each exchange on which registered)

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 x No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No x
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 x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨	Smaller reporting company ¨

(Do not check if a smaller reporting company)
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x
The aggregate market value of the registrant's common units held by non-affiliates of the registrant was approximately $1.4 billion as of June 30, 2015.
The registrant had 57,102,848 common units, 145,333,334 Class B units and 135,383,831 subordinated units outstanding as of February 12, 2016.
Documents incorporated by reference: None

CHENIERE ENERGY PARTNERS, L.P.
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DEFINITIONS

As commonly used in the liquefied natural gas industry, to the extent applicable and as used in this annual report, the terms listed below have the following meanings:

Common Industry and Other Terms

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 consisting primarily of methane (CH_4) that is in liquid form at near atmospheric pressure
MMBtu	million British thermal units, an energy unit
mtpa	million tonnes per annum
non-FTA countries	countries without a free trade agreement providing for national treatment for trade in natural gas and with which trade is permitted
SEC	Securities and Exchange Commission
SPA	LNG sale and purchase agreement
Train	An industrial facility comprised of a series of refrigerant compressor loops used to cool natural gas into LNG
TUA	terminal use agreement

Abbreviated Organizational Structure

The following diagram depicts our abbreviated organizational structure as of December 31, 2015, 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. (NYSE MKT: CQP) 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.” All statements, other than statements of historical facts, 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 terminals, liquefaction facilities, pipeline facilities or other projects, or any expansions 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 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, 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 and capital expenditures, 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 fact, are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” “continue,” the negative of su 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 due to factors described in this annual report and in the other reports and other information that we file with the SEC. These forward-looking statements speak only as of the date made, and other than as required by law, we undertake no obligation to publicly update or revise any forward-looking statement, 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 in 2006. Through our wholly owned subsidiary, SPLNG, we own and operate the regasification facilities at the Sabine Pass LNG terminal located on the Sabine-Neches Waterway less than four miles from the Gulf Coast. The Sabine Pass LNG terminal includes existing infrastructure of five LNG storage tanks with capacity of approximately 16.9 Bcfe, two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. We are developing and constructing natural gas liquefaction facilities (the “Liquefaction Project”) at the Sabine Pass LNG terminal adjacent to the existing regasification facilities through our wholly owned subsidiary, SPL. We are constructing five Trains and developing a sixth Train, each of which is expected to have a nominal production capacity of approximately 4.5 mtpa of LNG. We also own a 94-mile pipeline that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines (the “Creole Trail Pipeline”) through our wholly owned subsidiary, CTPL.

LNG is 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. The liquefaction of natural gas into LNG allows it to be shipped economically from areas of the world where natural gas is abundant and inexpensive to produce to other areas where natural gas demand and infrastructure exist to justify economically the use of LNG. LNG is transported using large oceangoing LNG tankers specifically constructed for this purpose. LNG regasification facilities offload LNG from LNG tankers, store the LNG prior to processing, heat the LNG to return it to a gaseous state and deliver the resulting natural gas into pipelines for transportation to market. Although results are consolidated for financial reporting, Cheniere Partners, SPL, SPLNG and CTPL operate with independent capital structures.

The following diagram depicts our abbreviated capital structure as of December 31, 2015:

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:

- completing construction and commencing operation of the first five Trains of the Liquefaction Project;
- obtaining the requisite long-term commercial contracts and financing to reach a final investment decision ("FID") regarding Train 6 of the Liquefaction Project;
- developing and operating our Trains safely, efficiently and reliably;
- making LNG available to our long-term SPA customers to generate steady and reliable revenues and operating cash flows;
- safely maintaining and operating the Sabine Pass LNG terminal and the Creole Trail Pipeline;
- developing business relationships for the marketing of additional long-term and short-term agreements for additional LNG volumes at the Sabine Pass LNG terminal; and
- expanding our existing asset base through acquisitions from Cheniere or third parties or our own development of the Liquefaction Project or complementary businesses or assets such as other LNG facilities, midstream assets, natural gas storage assets and natural gas pipelines.

Our Business

We have constructed and are operating regasification facilities at the Sabine Pass LNG terminal and are developing and constructing the Liquefaction Project.

Regasification Facilities

The Sabine Pass LNG terminal has operational regasification capacity of approximately 4.0 Bcf/d and aggregate LNG storage capacity of approximately 16.9 Bcfe. Approximately 2.0 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 Gas & Power North America, Inc. ("Total") and Chevron U.S.A. Inc. ("Chevron") has reserved approximately 1.0 Bcf/d of regasification capacity and is obligated to make monthly capacity payments to SPLNG aggregating approximately $125 million annually 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 2.0 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, continuing until at least 20 years after SPL delivers its first commercial cargo at the Liquefaction Project. SPL entered into a partial TUA assignment agreement with Total, whereby SPL will progressively gain access to Total's capacity and other services provided under Total's TUA with SPLNG. This agreement will provide SPL with additional berthing and storage capacity at the Sabine Pass LNG terminal that may be used to accommodate the development of Trains 5 and 6, provide increased flexibility in managing LNG cargo loading and unloading activity starting with the commencement of commercial operations of Train 3 and permit SPL to more flexibly manage its LNG storage capacity with the commencement of Train 1. 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.

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

Liquefaction Facilities

The Liquefaction Project is being developed and constructed at the Sabine Pass LNG terminal adjacent to the existing regasification facilities. We have received authorization from the FERC to site, construct and operate Trains 1 through 6. We commenced construction of Trains 1 and 2 and the related new facilities needed to treat, liquefy, store and export natural gas in August 2012. Construction of Trains 3 and 4 and the related facilities commenced in May 2013. In June 2015, we commenced construction of Train 5 and the related facilities.

The DOE has authorized the export of up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr) of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries for a 30-year term and to non-FTA countries for a 20-year term. The DOE further issued an order authorizing SPL to export up to the equivalent of approximately 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries for a 25-year period. SPL's application for authorization to export that same 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to non-FTA countries is currently pending at the DOE. Additionally, the DOE issued orders authorizing SPL to export up to a combined total of 503.3 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries and non-FTA countries for a 20-year term. A party to the proceeding requested a rehearing of the non-FTA order pertaining to the 503.3 Bcf/yr, and the DOE has not yet issued a final ruling on the rehearing request. In each case, the terms of these authorizations begin on the earlier of the date of first export thereunder or the date specified in the particular order, which ranges from 5 to 10 years from the date the order was issued. Furthermore, the DOE issued an order authorizing SPL to export up to 600 Bcf in total of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing on January 15, 2016.

As of December 31, 2015, the overall project completion percentages for Trains 1 and 2 and Trains 3 and 4 of the Liquefaction Project were approximately 97.4% and 79.5%, respectively. As of December 31, 2015, the overall project completion percentage for Train 5 of the Liquefaction Project was approximately 14.9% with engineering, procurement and construction approximately 41.9%, 20.5% and 0.1% complete, respectively. As of December 31, 2015, the overall project completion of each of our Trains was ahead of the contractual schedule. We produced our first LNG from Train 1 of the Liquefaction Project in February 2016. Based on our current construction schedule, we anticipate that Train 2 will produce LNG as early as mid-2016 and Trains 3 through 5 are expected to commence operations on a staggered basis thereafter.

The following table summarizes significant milestones and anticipated completion dates in the development of the Liquefaction Project:

Milestone	Target Date Trains 1 - 5
DOE export authorization	Received
Definitive commercial agreements	Completed 19.75 mtpa
BG Gulf Coast LNG, LLC	5.5 mtpa
Gas Natural Aprovisionamientos SDG S.A.	3.5 mtpa
Korea Gas Corporation	3.5 mtpa
GAIL (India) Limited	3.5 mtpa
Total	2.0 mtpa
Centrica plc	1.75 mtpa
EPC contracts	Completed
Financing	Completed
FERC authorization	Completed
Issue Notice to Proceed	Completed
Commence operations	2016 - 2019

Customers

SPL has entered into six fixed price, 20-year SPAs with third parties that in the aggregate equate to approximately 19.75 mtpa of LNG, which is approximately 88% of the expected aggregate nominal production capacity of Trains 1 through 5, that commence with the date of first commercial delivery for Trains 1 through 5. Under these SPAs, the customers will purchase LNG from SPL for a price consisting of a fixed fee plus 115% of Henry Hub per MMBtu of LNG. In certain circumstances, the customers may elect to cancel or suspend deliveries of LNG cargoes, in which case the customers would still be required to pay the fixed fee with respect to the contracted volumes that are not delivered. A portion of the fixed fee will be subject to annual adjustment 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 commences upon the start of operations of a specified Train. As of December 31, 2015, SPL had the following third-party SPAs:

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- BG Gulf Coast LNG, LLC (“BG”) has entered into an SPA that commences upon the date of first commercial delivery for Train 1 and includes an annual contract quantity of 182,500,000 MMBtu of LNG with a fixed fee of $2.25 per MMBtu and includes additional annual contract quantities of 36,500,000 MMBtu, 34,000,000 MMBtu and 33,500,000 MMBtu upon the date of first commercial delivery for Trains 2, 3 and 4, respectively, with a fixed fee of $3.00 per MMBtu. The total expected annual contracted cash flow from BG from fixed fees is approximately $723 million. In addition, SPL has agreed to make up to 500,000 MMBtu/d of LNG available to BG to the extent that Train 1 becomes commercially operable prior to the beginning of the first delivery window with a fixed fee of $2.25 per MMBtu, if produced. The obligations of BG are guaranteed by BG Energy Holdings Limited, a company organized under the laws of England and Wales.
- Gas Natural Aprovisionamientos SDG S.A. (“Gas Natural Fenosa”) has entered into an SPA that commences upon the date of first commercial delivery for Train 2 and includes an annual contract quantity of 182,500,000 MMBtu of LNG with a fixed fee of $2.49 per MMBtu, equating to expected annual contracted cash flow from fixed fees of approximately $454 million. In addition, SPL has agreed to make up to 285,000 MMBtu/d of LNG available to Gas Natural Fenosa to the extent that Train 2 becomes commercially operable prior to the beginning of the first delivery window with a fixed fee of $2.49 per MMBtu, if produced. The obligations of Gas Natural Fenosa are guaranteed by Gas Natural SDG S.A., a company organized under the laws of Spain.
- Korea Gas Corporation (“KOGAS”) has entered into an SPA that commences upon the date of first commercial delivery for Train 3 and includes an annual contract quantity of 182,500,000 MMBtu of LNG with a fixed fee of $3.00 per MMBtu, equating to expected annual contracted cash flow from fixed fees of approximately $548 million. KOGAS is organized under the laws of the Republic of Korea.
- GAIL (India) Limited (“GAIL”) has entered into an SPA that commences upon the date of first commercial delivery for Train 4 and includes an annual contract quantity of 182,500,000 MMBtu of LNG with a fixed fee of $3.00 per MMBtu, equating to expected annual contracted cash flow from fixed fees of approximately $548 million. GAIL is organized under the laws of India.
- Total has entered into an SPA that commences upon the date of first commercial delivery for Train 5 and includes an annual contract quantity of 104,750,000 MMBtu of LNG with a fixed fee of $3.00 per MMBtu, equating to expected annual contracted cash flow from fixed fees of approximately $314 million. The obligations of Total are guaranteed by Total S.A., a company organized under the laws of France.
- Centrica plc (“Centrica”) has entered into an SPA that commences upon the date of first commercial delivery for Train 5 and includes an annual contract quantity of 91,250,000 MMBtu of LNG with a fixed fee of $3.00 per MMBtu, equating to expected annual contracted cash flow from fixed fees of approximately $274 million. Centrica is organized under the laws of England and Wales.

In aggregate, the fixed fee portion to be paid by the third-party SPA customers is approximately $2.9 billion annually for Trains 1 through 5, with the applicable fixed fees starting from the commencement of commercial operations of the applicable Train. These fixed fees equal approximately $411 million, $564 million, $650 million, $648 million and $588 million for each of Trains 1 through 5, respectively.

In addition, Cheniere Marketing has entered into an SPA with SPL to purchase, at Cheniere Marketing’s option, any LNG produced by SPL in excess of that required for other customers.

Natural Gas Transportation 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 agreements to secure firm pipeline transportation capacity with CTPL and third-party pipeline companies. SPL has also entered into enabling agreements and natural gas purchase agreements with third parties in order to secure natural gas feedstock for the Liquefaction Project. As of December 31, 2015, SPL has secured up to approximately 2,154.2 million MMBtu of natural gas feedstock through natural gas purchase agreements.

Natural Gas Storage Services

For SPL's natural gas storage requirements, SPL has entered into firm storage services agreements with third parties. The storage services agreements will assist SPL in managing volatility in natural gas needs for the Liquefaction Project.

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 5, under which Bechtel charges a lump sum for all work performed and generally bears project cost risk 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 prices of the EPC contract for Trains 1 and 2, the EPC contract for Trains 3 and 4 and the EPC contract for Train 5 of the Liquefaction Project are approximately $4.1 billion, $3.8 billion and $3.0 billion, respectively, reflecting amounts incurred under change orders through December 31, 2015. Total expected capital costs for Trains 1 through 5 are estimated to be between $12.5 billion and $13.5 billion before financing costs and between $17.0 billion and $18.0 billion after financing costs, including, in each case, estimated owner’s costs and contingencies.

Pipeline Facilities

During the third quarter of 2015, CTPL completed construction of certain modifications to allow the Creole Trail Pipeline to be able to transport natural gas to the Sabine Pass LNG terminal.

Final Investment Decision on Train 6

We will contemplate making an FID to commence construction of Train 6 of the Liquefaction Project based upon, among other things, entering into an EPC contract, entering into acceptable commercial arrangements and obtaining adequate financing to construct the Train.

Governmental Regulation

The Sabine Pass LNG terminal is 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. This regulatory requirement increases our cost of operations and construction, and failure to comply with such laws could result in substantial penalties.

Federal Energy Regulatory Commission

The design, construction and operation of our liquefaction facilities and the export of LNG and the transportation of natural gas through the Creole Trail Pipeline are highly regulated activities. In order to site and construct the Sabine Pass LNG terminal, we received and are required to maintain authorization from the FERC under Section 3 of the Natural Gas Act of 1938 (“NGA”). The FERC’s approval under Section 3 of the NGA, as well as several other material governmental and regulatory approvals and permits, are required in order to site, construct and operate our liquefaction facilities.

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, although except as specifically provided in the EPAct, nothing in the EPAct is intended to affect otherwise applicable law related to any other federal agency’s authorities or responsibilities related to LNG terminals. 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. 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 LNG production capacity of Trains 1 through 4 from the currently authorized 803 Bcf/yr to 1,006 Bcf/yr so as to more accurately reflect the estimated maximum LNG production capacity. 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 denied rehearing. The party petitioned the U.S. Court of Appeals for the District of Columbia Circuit to review the February 2014 Order and the FERC Order Denying Rehearing, and that appeal is still pending. 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 April 2015.

In order to construct, own, operate and maintain the Creole Trail Pipeline, CTPL received 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. The FERC also 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 Dthd of feed gas to the Liquefaction Project. 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.

Several other material governmental and regulatory approvals and permits will be required prior to construction and operation of our liquefaction projects. In addition, the FERC authorization requires us to obtain certain additional FERC approvals as construction progresses. To date, we have been able to obtain these approvals as needed and the need for these approvals has not materially affected our construction progress. Throughout the life of our LNG terminals, we will be subject to regular reporting requirements to the FERC, the U.S. Department of Transportation and applicable state regulatory agencies regarding the operation and maintenance of our facilities.

In addition to the siting and construction authority with respect to the LNG terminals under the NGA, the FERC has authority to approve, and if necessary, set "just and reasonable rates" for the transportation or sale of natural gas in interstate commerce. In addition, under the NGA, our pipelines are not permitted to unduly discriminate or grant undue preference as to rates or the terms and conditions of service. The FERC has the authority to grant certificates allowing construction and operation of facilities used in interstate gas transportation and authorizing the provision of services. Under the NGA, the FERC's jurisdiction generally extends to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate consumption for domestic, commercial, industrial or any other use and to natural gas companies engaged in such transportation or sale. However, the FERC's jurisdiction does not extend to the production, gathering or local distribution of natural gas.

In general, the FERC's authority to regulate interstate natural gas pipelines and the services that they provide includes:
- rates and charges for natural gas transportation and related services;
- the certification and construction of new facilities;
- the extension and abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and
- various other matters.

The FERC's Standards of Conduct apply to interstate pipelines that conduct transmission transactions with an affiliate that engages in marketing functions. Interstate pipelines must treat all transmission customers on a not unduly discriminatory basis. The general principles of the 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. CTPL has established the required policies and procedures to comply with the FERC's Standards of Conduct and is subject to audit by the FERC to review compliance, policies and its training programs.

In 2002, the FERC concluded that it would apply light-handed regulation over the rates, terms and conditions agreed to by parties for LNG terminalling services, such that LNG terminal owners would not be required to provide open-access service at non-discriminatory rates or maintain a tariff or rate schedule on file with the FERC, as distinguished from the requirements applied to our FERC-regulated natural gas pipelines. The EPAct codified the FERC's policy, but those provisions expired on January 1, 2015. Nonetheless, we see no indication that the FERC intends to modify its longstanding policy of light-handed regulation of LNG terminals.

DOE Export License

The DOE has authorized the export of up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr) of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries for a 30-year term and to non-FTA countries for a 20-year term. The DOE further issued an order authorizing SPL to export up to the equivalent of approximately 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries for a 25-year period. SPL's application for authorization to export that same 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to non-FTA countries is currently pending at the DOE. Additionally, the DOE issued orders authorizing SPL to export up to a combined total of 503.3 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries and non-FTA countries for a 20-year term. A party to the proceeding requested a rehearing of the non-FTA order pertaining to the 503.3 Bcf/yr, and the DOE has not yet issued a final ruling on the rehearing request. In each case, the terms of these authorizations begin on the earlier of the date of first export thereunder or the date specified in the particular order, which ranges from 5 to 10 years from the date the order was issued. Furthermore, the DOE issued an order authorizing SPL to export up to 600 Bcf in total of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing on January 15, 2016.

Exports of natural gas to FTA countries are "deemed to be consistent with the public interest" and authorization to export LNG to FTA countries shall be granted by the DOE without "modification or delay." FTA countries which import LNG now or will do so by 2016 include Chile, Mexico, Singapore, South Korea and the Dominican Republic. Exports of natural gas to non-FTA countries are considered by the DOE in the context of a comment period whereby interveners are provided the opportunity to assert that such authorization would not be consistent with the public interest.

Pipelines

The Creole Trail Pipeline is also subject to regulation by the U.S. Department of Transportation ("DOT"), under the Pipeline and Hazardous Material Safety Administration ("PHMSA"), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities.

The Pipeline Safety Improvement Act of 2002, as amended ("PSIA"), which is administered by the PHMSA Office of Pipeline Safety, governs the areas of testing, education, training and communication. The PSIA requires pipeline companies to perform extensive integrity tests on natural gas transportation pipelines that exist in high population density areas designated as "high consequence areas." Pipeline companies are required to perform the integrity tests on a seven-year cycle. The risk ratings are based on numerous factors, including the population density in the geographic regions served by a particular pipeline, as well as the age and condition of the pipeline and its protective coating. Testing consists of hydrostatic testing, internal electronic testing, or direct assessment of the piping. In addition to the pipeline integrity tests, pipeline companies must implement a qualification program to make certain that employees are properly trained. Pipeline operators also must develop integrity management programs for gas transportation pipelines, which requires pipeline operators 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 preventive and mitigation actions.

In 2010, the PHMSA issued a final rule (known as "Control Room Management/Human Factors Rule") requiring pipeline operators to write and institute certain control room procedures that address human factors and fatigue management. In August 2011, the PHMSA issued an advanced notice of proposed rulemaking addressing whether changes are needed to the regulations governing the safety of gas transmission pipelines. Specifically, PHMSA is considering whether integrity management requirements should be changed, including whether the definition of "high consequence area" should be revised and whether additional restrictions should be placed on the use of specific pipeline assessment methods. The PHMSA is also considering whether to revise requirements for non-integrity management issues, such as mainline valves, corrosion control issues and the safety of gathering lines. This advanced notice of proposed rulemaking is still pending at the PHMSA.

In March 2015, the PHMSA issued a final rule amending the pipeline safety regulations to update and clarify certain regulatory requirements, including who can perform post-construction inspections on transmission pipelines. In May 2015, the PHMSA issued a notice of proposed rulemaking proposing to amend gas pipeline safety regulations regarding plastic piping systems used in gas services, including the installation of plastic pipe used for gas transmission lines. In July 2015, the PHMSA issued a notice of proposed rulemaking proposing to add a specific timeframe for operators' notification of accidents or incidents, as well as amending the safety regulations regarding operator qualification requirements by expanding the requirements to include new construction and certain previously excluded operation and maintenance tasks, requiring a program effectiveness review and adding new recordkeeping requirements. These notices of proposed rulemaking are still pending at the PHMSA.

Natural Gas Pipeline Safety Act of 1968 (“NGPSA”)

Louisiana and Texas administer federal pipeline safety standards under the NGPSA, which requires certain pipelines to comply with safety standards in constructing and operating the pipelines and subjects the pipelines to regular inspections. Failure to comply with the NGPSA may result in the imposition of administrative, civil and criminal remedies.

Pipeline Safety, Regulatory Certainty and Jobs Creation Act of 2011

The Creole Trail Pipeline is also subject to the Pipeline Safety, Regulatory Certainty and Jobs Creation Act of 2011, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities. Under the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, PHMSA has civil penalty authority up to $200,000 per day (increased from the prior $100,000), with a maximum of $2 million for any related series of violations (increased from the prior $1 million).

Other Governmental Permits, Approvals and Authorizations

The construction and operation of the Sabine Pass LNG terminal are subject to additional federal permits, orders, approvals and consultations required by other federal agencies, including the DOE, Advisory Council on Historic Preservation, 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, Environmental Protection Agency (the “EPA”) and U.S. Department of Homeland Security.

Three significant permits are the USACE Section 404 of the Clean Water Act/Section 10 of the Rivers and Harbors Act Permit (the “Section 10/404 Permit”), the Clean Air Act Title V (“Title V”) Operating Permit and the Prevention of Significant Deterioration (“PSD”) Permit, the latter two permits being issued by the LDEQ.

The application for revision of the Sabine Pass LNG terminal’s Section 10/404 Permit to authorize construction of Train 1 through Train 4 was submitted in January 2011. The process included a public comment period which commenced in March 2011 and closed in April 2011. The revised Section 10/404 Permit was received from the USACE in March 2012. An application for a further revision to the Section 10/404 Permit, to address wetlands impacted by the construction of Trains 5 and 6, was received from the USACE in June 2015. The USACE acted in the capacity as a cooperating agency in the FERC’s NEPA review process. In addition, a Section 10/404 permit application is pending with respect to the expansion of the Creole Trail Pipeline. These permits will require us to provide mitigation to compensate for the wetlands impacted by the respective projects. The application to amend the Sabine Pass LNG terminal’s existing Title V and PSD permits to authorize construction of Train 1 through Train 4 was initially submitted in December 2010 and revised in March 2011. The process included a public comment period from June 2011 to August 2011 and a public hearing in August 2011. The final revised Title V and PSD permits were issued by the LDEQ in December 2011. Although these permits are final, a petition with the EPA has been filed pursuant to the Clean Air Act requesting that the EPA object to the Title V permit. The EPA has not ruled on this petition. In June 2012, we applied to the LDEQ for a further amendment to the Title V and PSD permits to reflect proposed modifications to the Liquefaction Project that were filed with the FERC in October 2012. The LDEQ issued the amended PSD and Title V permits in March 2013. These permits are final. In September 2013, Cheniere Partners applied to the LDEQ for another amendment to its PSD and Title V permits seeking approval to, among other things, construct and operate Trains 5 and 6. The LDEQ issued the amended PSD and Title V permits in June 2015. These permits are final.

CTPL was issued new Title V and PSD permits for the proposed modifications to the Creole Trail Pipeline system by the LDEQ in November 2013.

In August 2014, the Sabine Pass LNG terminal's existing wastewater discharge permit was modified by LDEQ to authorize the discharge of wastewaters from the liquefaction facilities, including wastewaters generated with respect to the anticipated operations of Trains 5 and 6.

The Sabine Pass LNG terminal is subject to DOT safety regulations and standards for the transportation and storage of LNG and regulations of the U.S. Coast Guard relating to maritime safety and facility security.

Commodity Futures Trading Commission (“CFTC”)

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) provides 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 certain classes of swaps 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) establish position limits on certain swaps and futures products, and (6) otherwise enhance the rulemaking and enforcement authority of the CFTC and the SEC regarding the derivatives markets. As required by the Dodd-Frank Act, the CFTC, the SEC and other regulators have been promulgating rules and regulations implementing the regulatory provisions of the Dodd-Frank Act, although neither the CFTC nor the SEC has yet adopted or implemented all of the rules required by the Dodd-Frank Act. In addition, the CFTC and its staff regularly issue rule amendments and guidance, policy statements and letters interpreting or taking no-action positions, including time-limited no action positions, regarding the derivatives provisions of the Dodd-Frank Act and the rules of the CFTC under these provisions.

A provision of the Dodd-Frank Act requires the CFTC, in order to diminish or prevent excessive speculation in commodity markets, to adopt rules imposing new position limits on futures contracts, options contracts and economically equivalent physical commodity 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 proposed position limits rules that would modify and expand the applicability of position limits on the amounts of certain core futures contracts and economically equivalent futures contracts, options contracts 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 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, six classes of over-the-counter (“OTC”) interest rate and 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 any other classes of swaps, including swaps relating to physical commodities, for mandatory clearing, 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 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 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 commercial end users who qualify for the end user exception from the mandatory clearing requirement or certain other counterparties. We expect to qualify as such a commercial end user with respect to the swaps that we enter into to hedge our commercial risks. The Dodd-Frank Act’s swaps regulatory provisions and the related rules may also adversely affect our existing derivative contracts and restrict our ability to monetize such contracts, cause us to restructure certain contracts, reduce the availability of derivatives to protect against risks or to optimize assets, adversely affect our ability to execute our hedging strategies and impact the liquidity of certain swaps products, all of which could increase our business costs.

Under the Commodity Exchange Act as amended by the Dodd-Frank Act, the CFTC is directed generally to prevent manipulation, including by fraudulent or deceptive practices, in two markets: (1) physical commodities traded in interstate commerce, including physical energy and other commodities, as well as (2) financial instruments, such as futures, options and swaps. 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 or deceptive schemes in the physical commodities, futures, options and swaps markets. Should we violate these laws and regulations, we could be subject to a CFTC 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 may impose substantial penalties for noncompliance and substantial liabilities for pollution. Many of these laws and regulations restrict or prohibit the types, quantities and concentration of substances that can be released into the environment and can lead to substantial 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 operation 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 for multiple sections of the economy. This rule requires mandatory reporting of greenhouse gas (“GHG”) emissions from stationary fuel combustion sources as well as all fugitive emissions throughout LNG terminals. From time to time, Congress has considered proposed legislation directed at reducing GHG emissions, and the EPA has defined GHG emissions thresholds for requiring certain permits for new and existing industrial sources. 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, financial position, operating results and cash flows.

Coastal Zone Management Act (“CZMA”)

The Sabine Pass LNG terminal is subject to the review and possible requirements of the CZMA throughout the construction of facilities located within the coastal zone. 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).

Resource Conservation and Recovery Act (“RCRA”)

The federal RCRA and comparable state statutes govern the disposal of solid and hazardous wastes. In the event such wastes are generated in connection with our facilities, we will be subject to regulatory requirements affecting the handling, transportation, treatment, storage and disposal of such wastes

Endangered Species Act

The Sabine Pass LNG terminal may be restricted by requirements under the Endangered Species Act, which seeks to protect endangered or threatened animal, fish and plant species and designated habitats.

Market Factors and Competition

SPLNG currently does not experience competition for its terminal capacity because the entire approximately 4.0 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.

The Liquefaction Project currently does not experience competition with respect to Trains 1 through 5. SPL has entered into six fixed price, 20-year SPAs with third parties that will utilize substantially all of the liquefaction capacity available from these Trains. Each customer will be required to pay an escalating fixed fee for its annual contract quantity even if it elects not to purchase any LNG from us.

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 developing a natural gas liquefaction facility near Corpus Christi, Texas and has entered into eight fixed price, 20-year third-party SPAs 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.

Our ability to enter into additional long-term SPAs to underpin the development of additional Trains, sell any quantities of LNG available under the SPAs with Cheniere Marketing, or develop new projects is subject to market factors, including 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, economic growth in developing countries, investment in energy infrastructure, the rate of fuel switching for power generation from coal, nuclear or oil to natural gas and access to 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 23 Tcf between 2013 and 2025, with LNG increasing its current share of approximately ten percent of the global market. Wood Mackenzie forecasts that global demand for LNG will increase by 72%, from approximately 245 mtpa, or 11.9 Tcf, in 2015, to 421 mtpa, or 20.5 Tcf, in 2025 and that LNG production from existing facilities and new facilities already under construction will be able to supply the market with 365 mtpa in 2025, resulting in a market need for construction of additional facilities capable of producing an incremental 56 mtpa of LNG. We believe our new project that does not already have capacity sold under long-term contracts is competitive and well-positioned to capture a portion of this incremental market need.

We have limited exposure, particularly in the LNG terminal business for our five Trains under construction, to the decline in oil prices, even if it persists for more than 12 months, 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. To date, we have contracted approximately 19.75 mtpa of aggregate production capacity for Trains 1 through 5 of the Liquefaction Project with third-party customers. Train 6 has not been contracted to date. As of January 31, 2016, oil and gas futures 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, medium-term and short-term contracting of LNG from our terminal.

Subsidiaries

Our assets are generally held by or under 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, 2016, Cheniere and its subsidiaries had 888 full-time employees, including 488 employees who directly supported the Sabine Pass LNG terminal operations. See Note 11—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 Cheniere Partners, SPLNG, SPL and CTPL.

Available Information

Our common units have been publicly traded since March 21, 2007 and are traded on the NYSE MKT 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 of 1934, as amended (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. In addition, the public may read and copy any materials we file with the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (www.sec.gov) that contains reports and other information regarding issuers, like us, that file electronically with the SEC.

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 significant debt could materially and adversely affect our business, financial condition and prospects.

As of December 31, 2015, we had $11.8 billion of total debt outstanding on a consolidated basis (before debt discounts and debt premiums), excluding $135.2 million of 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 substantial additional debt and issue equity 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, the re-pricing of market risks and volatility in capital and financial markets. Our financing costs could increase or future borrowings or equity offerings may be unavailable to us or unsuccessful, which could cause us to be unable to pay or refinance our indebtedness or to fund our other liquidity needs. We also rely on borrowings under our credit facilities to fund our capital expenditures. If any of the lenders in the syndicates backing these facilities were unable to perform on its commitments, we may need to seek replacement financing, which may not be available as needed, or may be available in more limited amounts or on more expensive or otherwise unfavorable terms.

We have not been profitable historically. We may not achieve profitability or generate positive operating cash flow in the future.

We had net losses of $318.9 million, $410.0 million and $258.1 million for the years ended December 31, 2015, 2014 and 2013, respectively. We will continue to incur significant capital and operating expenditures while we develop and construct the Liquefaction Project. We currently expect that we will not begin to receive cash flows from operations under any SPA until early 2016, at the earliest. Any delays beyond the expected development period for Train 1 would prolong, and could increase the level of, operating losses and negative cash flows. Our future liquidity may also be affected by the timing of construction financing availability in relation to the incurrence of construction costs and other outflows and by the timing of receipt of cash flows under SPAs in relation to the incurrence of project and operating expenses. Moreover, many factors (including factors beyond our control) could result in a disparity between liquidity sources and cash needs, including factors such as construction delays and breaches of agreements. Our ability to generate any significant positive operating cash flow and achieve profitability in the future is dependent on our ability to successfully and timely complete the applicable Train.

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 and are pursuing a number of alternatives in order to finance the construction of Train 6, 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 Chevron and Total, each of which has entered into a TUA with SPLNG and agreed to pay SPLNG approximately $125 million annually, and upon satisfaction of the conditions precedent to payment thereunder, by six third-party customers that have entered into SPAs with SPL and agreed to pay SPL an aggregate of $2.9 billion annually in fixed fees. We are dependent on each customer's continued willingness and ability to perform its obligations under its SPA. We are also exposed to the credit risk of any guarantor of these customers' obligations under their respective TUA or SPA in the event that we must seek recourse under a guaranty. If any customer fails to perform its obligations under its TUA or SPA, 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 TUA or SPA.

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

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.

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.

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 would 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 swaps 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.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") establishes federal regulation of the over-the-counter ("OTC") derivatives market and made other amendments to the Commodity Exchange Act that are relevant to our business. The provisions of Title VII of the Dodd-Frank Act and the rules adopted thereunder by the Commodity Futures Trading Commission ("CFTC"), the SEC and other federal regulators 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 terminals and to secure natural gas feedstock for our Liquefaction Project.

The CFTC has proposed new rules setting limits on the positions in certain core futures contracts, economically equivalent futures contracts, options contracts and swaps for or linked to certain physical commodities, including Henry Hub natural gas, held by market participants, with limited exemptions for certain bona fide hedging and other types of transactions. Under the CFTC's proposed rules regarding aggregation of positions, a party that controls the trading of, or owns 10% or more of the equity interests in, another party will have to aggregate the positions of the controlled party with its own positions for purposes of determining compliance with position limits unless an exemption applies. Upon the adoption and effectiveness of final CFTC position limits and aggregation rules, 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 and aggregation rules may become final and effective.

Under the Dodd-Frank Act and the rules adopted thereunder, we may be required to clear through a derivatives clearing organization any swaps into which we enter that fall within a class of swaps designated by the CFTC for mandatory clearing and we could have to execute trades in such swaps on certain trading platforms. The CFTC has designated six classes of interest rate swaps and credit default swaps for mandatory clearing, but has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to 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 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. Moreover, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging.

As required by the Dodd-Frank Act, the CFTC and the federal banking regulators have adopted rules requiring certain market participants to collect margin with respect to uncleared swaps from their counterparties that are financial end users and certain registered swap dealers and major swap participants. The requirements of those rules are to be phased in commencing on September 1, 2016. Although we believe we will qualify as a non-financial end user for purposes of these rules, were we not to do so and have 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, 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 regulatory requirements on swaps market participants, including swap dealers and other swaps entities as well as certain regulations on end users of swaps, including regulations relating to swap documentation, reporting and recordkeeping, and certain business conduct rules applicable to swap dealers and other swaps entities. Together with the Basel III capital requirements on certain swaps market participants, these regulations 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, 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.

Risks Relating to Our Business

Operation of the Sabine Pass LNG terminal, the Liquefaction Project 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 and our other existing and proposed LNG facilities 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.

We may not be successful in implementing our proposed business strategy to provide liquefaction capabilities at the Sabine Pass LNG terminal adjacent to the existing regasification facilities.

It will take several years to construct the Liquefaction Project, and even if successfully constructed, the Liquefaction Project would be subject to the operating risks described herein. Accordingly, there are many risks associated with the Liquefaction Project, and if we are not successful in implementing our business strategy, we may not be able to generate cash flows, which could have a material adverse impact on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Cost overruns and delays in the completion of one or more 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 do not have any prior experience in constructing liquefaction facilities, and no liquefaction facilities have been constructed and placed in service in the United States in over 40 years. 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.

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 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.

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 counterparties.

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. 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.

Our ability to complete development of Train 6 will be contingent on our ability to obtain additional funding. If we are unable to obtain sufficient funding, we may be unable to complete our business plan and our business may ultimately be unsuccessful.

We will require significant additional funding to be able to commence construction of Train 6, which we may not be able to obtain at a cost that results in positive economics, or at all. The inability to achieve acceptable funding may cause a delay in the development of Train 6, and we may not be able to complete our business plan. Even if we are able to obtain funding, the funding may be inadequate to cover any increases in costs or delays in completion of Train 6, which may 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. 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.

To maintain the cryogenic readiness of the Sabine Pass LNG terminal, SPLNG may need to purchase and process LNG. SPLNG's TUA customers, including SPL, have the obligation to procure LNG if necessary for the Sabine Pass LNG terminal to maintain its cryogenic state. If they fail to do so, SPLNG may need to procure such LNG.

SPLNG needs to maintain the cryogenic readiness of the Sabine Pass LNG terminal. Together with SPL, the two third-party TUA customers have the obligation to maintain minimum inventory levels, and, under certain circumstances, to procure LNG to maintain the cryogenic readiness of the terminal. In the event that aggregate minimum inventory levels are not maintained, SPLNG has the right to procure a cryogenic readiness cargo to cure a minimum inventory condition, and to be reimbursed by each TUA customer for their allocable share of the LNG acquisition costs. If SPLNG is not able to obtain financing on acceptable terms, it will need to maintain sufficient working capital for such a purchase until it receives reimbursement for the allocable costs of the LNG from its TUA customers or sells the regasified LNG.

SPLNG may be required to purchase natural gas to provide fuel at the Sabine Pass LNG terminal, which would increase operating costs and could have a material adverse effect on our operating results.

SPLNG's TUAs provide for an in-kind deduction of 2% of the LNG delivered to the Sabine Pass LNG terminal, which it uses primarily as fuel for revaporization and self-generated power and to cover natural gas unavoidably lost at the facility. There is a risk that this 2% in-kind deduction will be insufficient for these needs and that SPLNG will have to purchase additional natural gas from third parties. SPLNG will bear the cost and risk of changing prices for any such fuel.

Hurricanes or other disasters could result in an interruption of our operations, a delay in the completion of the Liquefaction Project, higher construction costs and the deferral of the dates on which payments are due to SPL under the SPAs, all of which could adversely affect us.

In August and September of 2005, Hurricanes Katrina and Rita, respectively, damaged coastal and inland areas located in Texas, Louisiana, Mississippi and Alabama, resulting in the temporary suspension of construction of the Sabine Pass LNG terminal. In September 2008, Hurricane Ike struck the Texas and Louisiana coast, and the Sabine Pass LNG terminal experienced minor damage.

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. Changes in the global climate may have significant physical effects, such as increased frequency and severity of storms, floods and rising sea levels; if any such effects were to occur, they could have an adverse effect on our coastal 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 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 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 an order under Section 3 of the NGA authorizing the siting, construction and operation of six Trains, the FERC order requires us to obtain certain additional approvals in conjunction with ongoing construction and operations of the Liquefaction Project. We also have a pending application with the DOE for authorization to export LNG to non-FTA countries in addition to the orders previously granted to us by the DOE. Authorizations obtained from other federal and state regulatory agencies also contain ongoing conditions, and additional approval and permit requirements may be imposed. We cannot control the outcome of the review and approval process. We do not know whether or when any such approvals or permits can be obtained, or whether or not 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, we may not be able to recover our investment in our projects. 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, financial condition, operating results, 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, 2016, Cheniere and its subsidiaries had 888 full-time employees, including 488 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 of the Liquefaction Project. We 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. 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.

The executive officers of our general partner are officers and employees of Cheniere and its affiliates. Our general partner is currently in a transition process with respect to its Chief Executive Officer, which could affect our strategic direction or our business results. Further, 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.

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 Investments has entered into an amended and restated variable capacity rights agreement (the “VCRA”) with Cheniere

Marketing, under which Cheniere Marketing will be able to derive economic benefits to the extent it assists Cheniere Investments in commercializing Cheniere Investments' access to capacity at the Sabine Pass LNG terminal through its agreement with SPL, which has a TUA with SPLNG. In addition, Cheniere Marketing has entered into an SPA to purchase, at Cheniere Marketing's option, any LNG produced by SPL in excess of that required for other customers. 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 developing and constructing a natural gas liquefaction facility near Corpus Christi, Texas and has entered into eight third-party SPAs 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.

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 terminates 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 applicable liquefaction facility, 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 applicable liquefaction facility 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.

We are relying on third-party engineers to estimate 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.

If third-party pipelines and other facilities interconnected to our pipelines and facilities are or become unavailable to transport natural gas, this could have a material adverse effect on our business, financial condition, operating results, liquidity and prospects.

We will depend upon third-party pipelines and other facilities that will 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, financial condition, operating results, 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 liquefaction customers, we are required to deliver 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 delivery 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 operating hazards and uninsured risks, one or more of which may create significant liabilities and losses for us.

The operation of the Sabine Pass LNG terminal and construction of the Liquefaction Project is 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;
- 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;
- cost improvements that allow competitors to offer LNG regasification services or provide 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;
- 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 prices of LNG and 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 could adversely affect our customers and could materially and adversely affect our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Current operations at the Sabine Pass LNG terminal are dependent 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.

Operations at the Liquefaction Project will be 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 other alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas may be discovered outside 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 LNG exported to these markets.

Political instability in foreign countries that import or export natural gas, or strained relations between such countries and the United States, may also impede the willingness or ability of LNG suppliers and merchants in such countries to import or export LNG from or to the United States. Furthermore, some foreign suppliers of LNG may have economic or other reasons to obtain their LNG from, or direct their LNG to, non-United States markets or from or to our competitors' LNG 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, which may become available at a lower cost in certain markets.

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 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 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 LNG 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 Trains 1 through 5 of the Liquefaction Project and have an option for firm capacity for Train 6. We cannot control the regulatory and permitting approvals or third parties' construction times. If and when we need to replace one or more of our 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. 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, including cyberterrorism, or military campaigns may adversely impact our business.

A terrorist, including cyberterrorist, 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 one or more of the Trains, which would increase our costs and decrease our cash flows. A terrorist 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, including cyberterrorism, 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 and regulations that regulate and restrict, among other things, discharges to air, land and water, with particular respect to the protection of the environment and natural resources; the handling, storage and disposal of hazardous materials, hazardous waste and petroleum products; and remediation associated with the release of hazardous substances. 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. Violation of these laws and regulations could lead to substantial liabilities, fines and penalties or to capital expenditures related to pollution control equipment that could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Federal and state laws impose liability, without regard to fault or the lawfulness of the original conduct, for the release of certain types or quantities of hazardous substances into the environment. As the owner and operator of our facilities, we could be liable for the costs of cleaning up hazardous substances released into the environment at or from our facilities and for resulting damage to natural resources.

The Obama Administration is pursuing a number of regulatory and policy initiatives to reduce GHG emissions in the United States from a variety of sources. For example, in October 2015, the EPA promulgated a final rule to implement the Obama Administration’s Clean Power Plan, which is designed to reduce GHG emissions from power plants in the United States. Other federal and state initiatives are being considered or may be considered in the future to address GHG emissions through, for example, United States treaty commitments, direct regulation, a carbon emissions tax, or cap-and-trade programs. Such initiatives could affect the demand for or cost of natural gas, which we consume at the Sabine Pass LNG 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 through the Sabine-Neches Waterway less than four miles from the Gulf Coast, could cause additional expenditures, restrictions and delays in our business and to our proposed construction, 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 tariffs are subject to FERC regulation.

The Creole Trail Pipeline is subject to regulation by the FERC under the NGA and under the Natural Gas Policy Act of 1978. The FERC regulates the transportation of natural gas in interstate commerce, including the construction and operation of the Creole Trail Pipeline, the rates and terms of conditions of service and abandonment of facilities. Under the NGA, the rates charged by the Creole Trail Pipeline 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 CTPL fails to comply with all applicable statutes, rules, regulations and orders, the Creole Trail Pipeline could be subject to substantial penalties and fines.

Our FERC gas tariffs, including our pro forma transportation agreements, must be filed and approved by the FERC. Before we enter into a transportation agreement with a shipper that contains a term that materially deviates from our tariff, we must seek the FERC's approval. The FERC may approve the material deviation in the transportation agreement; however, in that case, the materially deviating terms must be made available to our other similarly-situated customers. If CTPL fails to seek the FERC's approval of a transportation agreement that materially deviates from our tariff, or if the FERC audits our contracts and finds deviations that appear to be unduly discriminatory, the FERC could conduct a formal enforcement investigation, resulting in serious penalties and/or onerous ongoing compliance obligations.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines. Under the EPAct, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1.0 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 damage.

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 federal Office of Pipeline Safety 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, we are 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.

We are 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 we fail to comply with the Federal Office of Pipeline Safety's rules and related regulations and orders, we 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.

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 2016 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 Corpus Christi liquefaction project. 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.

We are currently paying the initial quarterly distribution of $0.425 on each of our common units and the related distribution on the general partner units. We are currently not paying any distributions on the subordinated units. The Class B units are not entitled to receive distributions until they convert into common units. As of December 31, 2015, we had 57,083,723 common units outstanding. The aggregate initial quarterly distribution on these common units and the related general partner units is approximately $99 million per year. We are not currently generating sufficient operating surplus each quarter to pay the initial quarterly distribution on all of these units and therefore intend to use a portion of our accumulated operating surplus each quarter to enable us to make this distribution. We may not have sufficient operating surplus to continue paying the initial quarterly distribution on all of our common units before Trains 1 and 2 commence commercial operations, which is not expected to occur until at least 2016 or thereafter. Furthermore, if Trains 1 and 2 do not commence commercial operations as expected and the outstanding Class B units convert into common units, we may not have sufficient operating surplus to be able to pay the initial quarterly distribution on all common units then outstanding.

Accordingly, at least until Trains 1 and 2 commence commercial operations, 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 TUAs;
- performance by SPLNG of its obligations under the TUAs;
- performance by, and the level of cash receipts received from, Cheniere Marketing under the VCRA; 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 the ability of SPLNG to pay distributions to us under the indentures governing the $1.7 billion of 7.50% Senior Secured Notes due 2016 and $0.4 billion of 6.50% Senior Secured Notes due 2020, both issued by SPLNG (the "SPLNG Indentures") as a result of requirements for a debt service reserve account, a debt payment account and satisfaction of a fixed charge coverage ratio and the ability of SPL to pay distributions to us under its credit facilities and its 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 will 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, 2015, we had $11.8 billion of total consolidated indebtedness (before debt discounts and debt premiums). We anticipate incurring additional consolidated indebtedness in the future, including by issuing additional notes of our subsidiaries, including SPL. Any additional indebtedness incurred could be at higher interest rates and have different maturity dates and more restrictive covenants than our current outstanding indebtedness. Approximately $1.7 billion of our indebtedness will mature in 2016, $400.0 million will mature in 2017, $420.0 million will mature in 2020, $2.0 billion 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 and $2.0 billion will mature in 2025. In addition, SPL's $4.6 billion credit facilities will mature on the earlier of December 31, 2020 or the second anniversary of the Train 5 completion date, as defined in SPL's credit facilities. We are not generally required to make principal payments on any of our long-term indebtedness prior to maturity other than SPL's credit facilities. 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. Our TUAs with Total and Chevron, which provide substantially all of our current operating cash flows, will expire in 2029 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, 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, SPLNG may not make distributions under the SPLNG Indentures until, among other requirements, a deposit has been made in an interest payment account for one-sixth of the semi-annual interest payment multiplied by the number of elapsed months since the last semi-annual interest payment, a deposit has been made to a permanent debt service reserve fund for one semi-annual interest payment and a fixed charge coverage ratio test of 2:1 is satisfied. SPLNG also is not permitted to make cash distributions if its consolidated cash flow is not at least twice its fixed charges, calculated as required in the SPLNG Indentures. In order to satisfy this fixed charge coverage ratio test, we estimate that SPLNG's consolidated cash flow, as defined in such indentures, must be greater than approximately $340 million. Thus, TUA payments from SPL and either Chevron or Total are needed to satisfy the test. If the fixed charge coverage ratio test is not satisfied, SPLNG will not be permitted by the SPLNG Indentures to make distributions to us, which may prevent us from making distributions to our unitholders.

SPL is likewise restricted from making distributions under the agreements governing its indebtedness generally until, among other requirements, substantial completion of Trains 1 and 2 has occurred, 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 SPLNG and SPL to make distributions or incur additional indebtedness, the agreements governing their indebtedness also contain various other covenants that may prevent them from engaging in beneficial transactions, including limitations on their ability to:

- make certain investments;
- purchase, redeem or retire equity interests;

- issue preferred stock;
- sell or transfer assets;
- incur liens;
- enter into transactions with affiliates;
- consolidate, merge, sell or lease all or substantially all of its assets; and
- enter into sale and leaseback transactions.

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 11—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.

We have not paid any distributions on our subordinated units with respect to the quarters ended on or after June 30, 2010. We may not have sufficient cash available for distributions on our subordinated units in the future. Any further reduction in the amount of cash available for distributions could impact our ability to pay the initial quarterly distribution on our common units in full or at all.

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

Risks Relating to an Investment in Us and Our Common Units

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

Cheniere owns and, indirectly through Cheniere Holdings, 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 will 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 pipelines 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 will 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 will 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, Class B 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. An affiliate of Cheniere owns 55.9% of our outstanding common units, Class B 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, between January 1, 2015 and December 31, 2015, the market price of our common units ranged between $20.15 and $34.55. 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 units 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;

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- 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 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 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. An affiliate of Cheniere owns 11,963,488 common units, 135,383,831 subordinated units and 45,333,334 Class B units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier. 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, which is currently a maximum of 35%, 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 to you.

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. For example, 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. Further, the U.S. Treasury Department and the Internal Revenue Service ("IRS") have issued proposed regulations under Section 7704(d)(1)(E) of the Code, interpreting the scope of qualifying income for publicly traded partnerships by providing industry-specific guidance with respect to activities that will generate qualifying income for purposes of the qualifying income requirement. The proposed regulations, once issued in final form, may change interpretations of the current law relating to the characterization of income as qualifying income and could modify the amount of our gross income we are able to treat as qualifying income for purposes of the qualifying income requirement. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes 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 recently issued 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 the use 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 change in tax treatment of our partnership, or 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.

Recently enacted legislation, applicable to partnership tax years beginning after 2017, alters the procedures for auditing large partnerships and for assessing and collecting taxes due (including penalties and interest) as a result of a partnership-level federal income tax audit. Under the new rules, unless we are eligible to, and do, elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed. If we are required to pay taxes, penalties and interest as a result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited tax year.

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.

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.

Non-U.S. investors face unique tax issues from owning common units that may result in adverse tax consequences to them.

Non-U.S. investors who own common units will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income and distributions to non-U.S. investors will generally be reduced by withholding taxes at the highest applicable effective tax rate. The IRS has taken the position that a non-U.S. investor's gain on the sale of common units is subject to United States federal income tax.

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.

The sale or exchange of 50% or more of the total interest in our capital and profits during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available as described below) for one fiscal year. Our technical termination could also result in a deferral of depreciation deductions allowable in computing our taxable income.

In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being includable in the unitholder's taxable income for the year of termination. Our technical termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership, we would be required to make new tax elections and we could be subject to penalties if we are unable to determine that a technical termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year, notwithstanding two partnership tax years.

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.

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A unitholder whose common units are loaned to a “short seller” to cover a short sale of 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 a unitholder whose common units are loaned to a “short seller” to cover a short sale of units 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 to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, 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 loan to a short seller are urged to consult with their tax advisor about whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing 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. In the opinion of management, as of December 31, 2015, there were no pending legal matters that would reasonably be expected to have a material impact on our consolidated operating results, financial position or cash flows.

ITEM 4. MINE SAFETY DISCLOSURE

None.

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 MKT under the symbol “CQP” commencing with our initial public offering on March 21, 2007. The table below presents the high and low sales prices per common unit, as reported by the NYSE MKT, and cash distributions to common unitholders for each quarter during 2015 and 2014.

	High	Low	Cash Distributions Per Common Unit (1)	Cash Distributions Per Subordinated Unit (2)	Cash Distributions Per Class B Unit (3)
2015					
First Quarter	$32.70	$28.36	$ 0.425	$ —	$ —
Second Quarter	34.55	29.77	0.425	—	—
Third Quarter	32.54	20.53	0.425	—	—
Fourth Quarter	29.59	20.15	0.425	—	—
2014					
First Quarter	$30.23	$27.42	$ 0.425	$ —	$ —
Second Quarter	34.60	29.71	0.425	—	—
Third Quarter	33.48	30.96	0.425	—	—
Fourth Quarter	33.00	25.08	0.425	—	—

(1) We also paid cash distributions to our general partner with respect to its 2% general partner interest.

(2) We have not paid distributions on our subordinated units since the distribution made with respect to the quarter ended March 31, 2010. See “Subordination Period” below.

(3) Class B units are not entitled to cash distributions except in the event of a liquidation (or merger, combination or sale of substantially all of our assets). See “Class B Units” below.

A distribution for the quarter ended December 31, 2015 of $0.425 per common unit was paid on February 12, 2016. In addition, we paid cash distributions to our general partner with respect to its 2% general partner interest.

As of February 12, 2016, we had (1) 57.1 million common units outstanding held by approximately 12 record owners and (2) 145.3 million Class B units outstanding, of which 100.0 million Class B units were held by Blackstone CQP Holdco and 45.3 million Class B units were held by Cheniere Holdings.

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 SPLNG Indentures described in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” may prohibit SPLNG from making cash distributions to us under certain circumstances, which could limit our ability to make distributions.

Upon the closing of our initial public offering, Cheniere received 135,383,831 subordinated units. Below is a description of our cash distribution policy regarding common, subordinated and Class B 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 Holdings owns all of the 135,383,831 subordinated units, representing 39.3% of the limited partner interests in us as of December 31, 2015. 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 the assignment of Cheniere Marketing's TUA to Cheniere Investments, effective July 1, 2010, our available cash for distributions was reduced. Therefore, we have not paid distributions on our subordinated units since the distribution made with respect to the quarter ended March 31, 2010.

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 (assuming conversion of the Class B 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 (assuming conversion of the Class B 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 (assuming conversion of the Class B 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 incentive distribution rights 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 (assuming conversion of the Class B units), 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 (assuming conversion of the Class B 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 LNG sale and purchase agreements 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.

Class B Units

During 2012, Blackstone CQP Holdco and Cheniere completed their purchases of Class B units for total consideration of $1.5 billion and $500.0 million, respectively. Proceeds from the financings are being used to fund a portion of the costs of developing, constructing and placing into service the Liquefaction Project. In May 2013, Cheniere purchased an additional 12.0 million Class B units for consideration of $180.0 million in connection with our acquisition of Cheniere's ownership interests in CTPL and Cheniere Pipeline GP Interests, LLC (collectively, "the Creole Trail Pipeline Business"), described in Note 3—Summary of Significant Accounting Policies of our Notes to Consolidated Financial Statements. The Class B units are not entitled to cash distributions except in the event of our liquidation or a merger, consolidation or other combination of us with another person or the sale of all or substantially all of our assets. The Class B units are subject to conversion, mandatorily or at the option of the holders of the Class B units under specified circumstances, into a number of common units based on the then-applicable conversion value of the Class B units. On a quarterly basis beginning on the initial purchase date of the Class B units, the conversion value of the Class B units increases at a compounded rate of 3.5% per quarter, subject to an additional upward adjustment for certain equity and debt financings. The holders of Class B units have a preference over the holders of the subordinated units in the event of a liquidation (or merger, combination or sale of substantially all of our assets).

General Partner Units and Incentive Distribution Rights

Incentive distribution rights 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 incentive distribution rights but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement.

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:

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest Distributions 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 (in thousands, except per unit data) are derived from our audited Consolidated Financial Statements for the periods indicated. 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, 2015	2014	2013	2012	2011
Revenues (including transactions with affiliates)	$270,028	$268,698	$268,191	$264,498	$283,888
Operating costs and expenses (including transactions with affiliates)	266,986	268,183	300,220	226,875	164,054
Income (loss) from operations	3,042	515	(32,029)	37,623	119,834
Interest expense, net of capitalized interest	(184,600)	(177,032)	(178,400)	(171,646)	(173,590)
Net loss	(318,891)	(410,036)	(258,117)	(175,431)	(53,560)
Net income (loss) per common unit	$(0.43)	$—	$(0.03)	$0.27	$1.23
Weighted average units outstanding	57,081	57,079	54,235	33,470	27,910

	December 31, 2015	2014	2013	2012	2011
Cash and cash equivalents	$146,221	$248,830	$351,032	$419,292	$81,415
Restricted cash (current)	274,557	195,702	227,652	92,519	13,732
Non-current restricted cash	13,650	544,465	1,025,056	272,425	82,394
Property, plant and equipment, net	11,931,602	8,978,356	6,383,939	3,219,592	2,044,020
Total assets	12,996,327	10,387,515	8,516,783	4,265,787	2,267,990
Current debt, net	1,676,197	—	—	—	—
Long-term debt, net	10,178,681	8,991,333	6,576,273	2,167,113	2,192,418
Total partners' equity (deficit)	712,931	1,130,729	1,639,744	1,879,978	(14,411)

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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 in "Financial Statements and Supplementary Data." 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. Through our wholly owned subsidiary, SPLNG, we own and operate the regasification facilities at the Sabine Pass LNG terminal located on the Sabine-Neches Waterway less than four miles from the Gulf Coast. The Sabine Pass LNG terminal includes existing infrastructure of five LNG storage tanks with capacity of approximately 16.9 Bcfe, two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. We are developing and constructing natural gas liquefaction facilities (the "Liquefaction Project") at the Sabine Pass LNG terminal adjacent to the existing regasification facilities through our wholly owned subsidiary, SPL. We are constructing five Trains and developing a sixth Train, each of which is expected to have a nominal production capacity of approximately 4.5 mtpa of LNG. We also own a 94-mile pipeline that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines (the "Creole Trail Pipeline") through our wholly owned subsidiary, CTPL.

Overview of Significant Events

Our significant accomplishments since January 1, 2015 and through the filing date of this Form 10-K include the following:

- SPL issued an aggregate principal amount of $2.0 billion of 5.625% Senior Secured Notes due 2025 (the "2025 SPL Senior Notes"). Net proceeds from the offering will be used to pay a portion of the capital costs associated with the construction of the first four Trains of the Liquefaction Project.
- We received authorization from the FERC to site, construct and operate Trains 5 and 6 of the Liquefaction Project.
- SPL received authorization from the DOE to export up to a combined total of the equivalent of 503.3 Bcf/yr of domestically produced LNG by vessel from Trains 5 and 6 of the Liquefaction Project to non-FTA countries for a 20-year term.
- SPL and Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") entered into a lump sum turnkey contract for the engineering, procurement and construction of Train 5 of the Liquefaction Project (the "EPC Contract (Train 5)").
- SPL entered into four credit facilities (collectively, the "2015 SPL Credit Facilities") aggregating $4.6 billion, which terminated and replaced its existing credit facilities. The 2015 SPL Credit Facilities will be used to fund a portion of the costs of developing, constructing and placing into operation Trains 1 through 5 of the Liquefaction Project.
- SPL issued a notice to proceed to Bechtel under the EPC Contract (Train 5).

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- SPL entered into a $1.2 billion Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement (the "SPL Working Capital Facility"), which replaced the $325.0 million senior letter of credit and reimbursement agreement that was entered into in April 2014 (the "SPL LC Agreement"). The SPL Working Capital Facility will be used primarily for certain working capital requirements related to developing and placing into operation the Liquefaction Project.
- In January 2016, we engaged 13 financial institutions to act as Joint Lead Arrangers, Mandated Lead Arrangers and other participants to assist in the structuring and arranging of up to approximately $2.8 billion of senior secured credit facilities. Proceeds from these new credit facilities are intended to be used by us to prepay $400.0 million of the CTPL term loan facility (the "CTPL Term Loan"), to redeem or repay $1,665.5 million of the 7.50% Senior Secured Notes due 2016 (the "2016 SPLNG Senior Notes") and $420.0 million of the 6.50% Senior Secured Notes due 2020 (the "2020 SPLNG Senior Notes" and collectively with the 2016 SPLNG Senior Notes, the "SPLNG Senior Notes"), to pay associated transaction fees, expenses and make-whole amounts, if applicable, and for our general business purposes.

Liquidity and Capital Resources

Cash and Cash Equivalents

As of December 31, 2015, we had $146.2 million of cash and cash equivalents and $288.3 million of current and non-current restricted cash (which included current and non-current restricted cash available to us, SPL, CTPL and SPLNG) designated for the following purposes: $189.3 million for the Liquefaction Project; $7.9 million for CTPL; and $91.1 million for interest payments related to the SPLNG Senior Notes described below.

Sabine Pass LNG Terminal

Regasification Facilities

The Sabine Pass LNG terminal has operational regasification capacity of approximately 4.0 Bcf/d and aggregate LNG storage capacity of approximately 16.9 Bcfe. Approximately 2.0 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 Gas & Power North America, Inc. ("Total") and Chevron U.S.A. Inc. ("Chevron") has reserved approximately 1.0 Bcf/d of regasification capacity and is obligated to make monthly capacity payments to SPLNG aggregating approximately $125 million annually 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 2.0 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, continuing until at least 20 years after SPL delivers its first commercial cargo at the Liquefaction Project. SPL entered into a partial TUA assignment agreement with Total, whereby SPL will progressively gain access to Total's capacity and other services provided under Total's TUA with SPLNG. This agreement will provide SPL with additional berthing and storage capacity at the Sabine Pass LNG terminal that may be used to accommodate the development of Trains 5 and 6, provide increased flexibility in managing LNG cargo loading and unloading activity starting with the commencement of commercial operations of Train 3 and permit SPL to more flexibly manage its LNG storage capacity with the commencement of Train 1. 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.

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

Liquefaction Facilities

The Liquefaction Project is being developed and constructed at the Sabine Pass LNG terminal adjacent to the existing regasification facilities. We have received authorization from the FERC to site, construct and operate Trains 1 through 6. We commenced construction of Trains 1 and 2 and the related new facilities needed to treat, liquefy, store and export natural gas in August 2012. Construction of Trains 3 and 4 and the related facilities commenced in May 2013. In June 2015, we commenced construction of Train 5 and the related facilities.

The DOE has authorized the export of up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr) of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries for a 30-year term and to non-FTA countries for a 20-year term. The DOE further issued an order authorizing SPL to export up to the equivalent of approximately 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries for a 25-year period. SPL's application for authorization to export that same 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to non-FTA countries is currently pending at the DOE. Additionally, the DOE issued orders authorizing SPL to export up to a combined total of 503.3 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries and non-FTA countries for a 20-year term. A party to the proceeding requested a rehearing of the non-FTA order pertaining to the 503.3 Bcf/yr, and the DOE has not yet issued a final ruling on the rehearing request. In each case, the terms of these authorizations begin on the earlier of the date of first export thereunder or the date specified in the particular order, which ranges from 5 to 10 years from the date the order was issued. Furthermore, the DOE issued an order authorizing SPL to export up to 600 Bcf in total of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing on January 15, 2016.

As of December 31, 2015, the overall project completion percentages for Trains 1 and 2 and Trains 3 and 4 of the Liquefaction Project were approximately 97.4% and 79.5%, respectively. As of December 31, 2015, the overall project completion percentage for Train 5 of the Liquefaction Project was approximately 14.9% with engineering, procurement and construction approximately 41.9%, 20.5% and 0.1% complete, respectively. As of December 31, 2015, the overall project completion of each of our Trains was ahead of the contractual schedule. We produced our first LNG from Train 1 of the Liquefaction Project in February 2016. Based on our current construction schedule, we anticipate that Train 2 will produce LNG as early as mid-2016 and Trains 3 through 5 are expected to commence operations on a staggered basis thereafter.

Customers

SPL has entered into six fixed price, 20-year SPAs with third parties that in the aggregate equate to approximately 19.75 mtpa of LNG, which is approximately 88% of the expected aggregate nominal production capacity of Trains 1 through 5, that commence with the date of first commercial delivery for Trains 1 through 5. Under these SPAs, the customers will purchase LNG from SPL for a price consisting of a fixed fee plus 115% of Henry Hub per MMBtu of LNG. In certain circumstances, the customers may elect to cancel or suspend deliveries of LNG cargoes, in which case the customers would still be required to pay the fixed fee with respect to the contracted volumes that are not delivered. A portion of the fixed fee will be subject to annual adjustment 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 commences upon the start of operations of a specified Train.

In aggregate, the fixed fee portion to be paid by the third-party SPA customers is approximately $2.9 billion annually for Trains 1 through 5, with the applicable fixed fees starting from the commencement of commercial operations of the applicable Train. These fixed fees equal approximately $411 million, $564 million, $650 million, $648 million and $588 million for each of Trains 1 through 5, respectively.

In addition, Cheniere Marketing has entered into an SPA with SPL to purchase, at Cheniere Marketing's option, any LNG produced by SPL in excess of that required for other customers.

All of our revenues from external customers and long-lived assets for each of the years ended December 31, 2015, 2014 and 2013 are attributed to or located in the United States.

Construction

SPL entered into lump sum turnkey contracts with Bechtel for the engineering, procurement and construction of Trains 1 through 5, under which Bechtel charges a lump sum for all work performed and generally bears project cost risk 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 prices of the EPC contract for Trains 1 and 2, the EPC contract for Trains 3 and 4 and the EPC Contract (Train 5) of the Liquefaction Project are approximately $4.1 billion, $3.8 billion and $3.0 billion, respectively, reflecting amounts incurred under change orders through December 31, 2015. Total expected capital costs for Trains 1 through 5 are estimated to be between $12.5 billion and $13.5 billion before financing costs and between $17.0 billion and $18.0 billion after financing costs, including, in each case, estimated owner’s costs and contingencies.

Final Investment Decision on Train 6

We will contemplate making a final investment decision (“FID”) to commence construction of Train 6 of the Liquefaction Project based upon, among other things, entering into an EPC contract, entering into acceptable commercial arrangements and obtaining adequate financing to construct the Train.

Capital Resources

We currently expect that SPL’s capital resources requirements with respect to Trains 1 through 5 of the Liquefaction Project will be financed through one or more of the following: borrowings, equity contributions from us and cash flows under the SPAs. We believe that with the net proceeds of borrowings, available commitments under the 2015 SPL Credit Facilities, available commitments under the SPL Working Capital Facility and cash flows from operations, we will have adequate financial resources available to complete Trains 1 through 5 of the Liquefaction Project and to meet our currently anticipated capital, operating and debt service requirements. We currently project that we will generate cash flow from the Liquefaction Project by early 2016.

Senior Secured Notes

As of December 31, 2015, our subsidiaries had seven series of senior secured notes outstanding (collectively, the “Senior Notes”):

- $1.7 billion of the 2016 SPLNG Senior Notes;
- $0.4 billion of the 2020 SPLNG Senior Notes;
- $2.0 billion of 5.625% Senior Secured Notes due 2021 issued by SPL (the “2021 SPL Senior Notes”);
- $1.0 billion of 6.25% Senior Secured Notes due 2022 issued by SPL (the “2022 SPL Senior Notes”);
- $1.5 billion of 5.625% Senior Secured Notes due 2023 issued by SPL (the “2023 SPL Senior Notes”);
- $2.0 billion of 5.75% Senior Secured Notes due 2024 issued by SPL (the “2024 SPL Senior Notes” and collectively with the 2021 SPL Senior Notes, the 2022 SPL Senior Notes, the 2023 SPL Senior Notes and the 2025 SPL Senior Notes, the “SPL Senior Notes”); and
- $2.0 billion of the 2025 SPL Senior Notes.

Interest on the SPL Senior Notes is payable semi-annually in arrears. Subject to permitted liens, the SPLNG Senior Notes are secured on a pari passu first-priority basis by a security interest in all of SPLNG’s equity interests and substantially all of SPLNG’s operating assets. The SPL Senior Notes are secured on a first-priority basis by a security interest in all of the membership interests in SPL and substantially all of SPL’s assets.

SPLNG may redeem all or part of its 2016 SPLNG Senior Notes at any time at a redemption price equal to 100% of the principal plus any accrued and unpaid interest plus the greater of:

- 1.0% of the principal amount of the 2016 SPLNG Senior Notes; or
- the excess of: (1) the present value at such redemption date of (a) the redemption price of the 2016 SPLNG Senior Notes plus (b) all required interest payments due on the 2016 SPLNG Senior Notes (excluding accrued but unpaid interest to the redemption date), computed using a discount rate equal to the treasury rate as of such redemption date plus 50 basis points; over (2) the principal amount of the 2016 SPLNG Senior Notes, if greater.

SPLNG may redeem all or part of the 2020 SPLNG Senior Notes at any time on or after November 1, 2016 at fixed redemption prices specified in the indenture governing the 2020 SPLNG Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. SPLNG may also, at its option, redeem all or part of the 2020 SPLNG Senior Notes at any time prior to November 1, 2016, at a “make-whole” price set forth in the indenture governing the 2020 SPLNG Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption.

At any time prior to three months before the respective dates of maturity for each series of the SPL Senior Notes, SPL may redeem all or part of such series of the SPL Senior Notes at a redemption price equal to the "make-whole" price set forth in the

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common indenture governing the SPL Senior Notes (the “SPL Indenture”), 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, 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.

Under the indentures governing the SPLNG Senior Notes (the “SPLNG Indentures”), except for permitted tax distributions, SPLNG may not make distributions until, among other requirements, deposits are made into debt service reserve accounts and a fixed charge coverage ratio test of 2:1 is satisfied. Under the SPL Indenture, SPL may not make any distributions until, among other requirements, substantial completion of Trains 1 and 2 has occurred, deposits are made into debt service reserve accounts as required and a debt service coverage ratio test of 1.25:1.00 is satisfied. During the years ended December 31, 2015, 2014 and 2013, SPLNG made distributions of $337.3 million, $346.9 million and $348.9 million, respectively, after satisfying all the applicable conditions in the SPLNG Indentures.

The SPL Indenture includes 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, the 2015 SPL Credit Facilities and the SPL Working Capital Facility.

2015 SPL Credit Facilities

In June 2015, SPL entered into the 2015 SPL Credit Facilities with commitments aggregating $4.6 billion. The 2015 SPL Credit Facilities are being used to fund a portion of the costs of developing, constructing and placing into operation Trains 1 through 5 of the Liquefaction Project. Borrowings under the 2015 SPL Credit Facilities may be refinanced, in whole or in part, at any time without premium or penalty; however, interest rate hedging and interest rate breakage costs may be incurred. As of December 31, 2015, SPL had $3.8 billion of available commitments and outstanding borrowings of $845.0 million under the 2015 SPL Credit Facilities.

Loans under the 2015 SPL Credit Facilities accrue interest at a variable rate per annum equal to, at SPL’s election, LIBOR or the base rate plus the applicable margin. The applicable margin for LIBOR loans ranges from 1.30% to 1.75%, depending on the applicable 2015 SPL Credit Facility, and the applicable margin for base rate loans is 1.75%. Interest on LIBOR loans is due and payable at the end of each LIBOR period and interest on base rate loans is due and payable at the end of each quarter. In addition, SPL is required to pay insurance/guarantee premiums of 0.45% per annum on any drawn amounts under the covered tranches of the 2015 SPL Credit Facilities. The 2015 SPL Credit Facilities also require SPL to pay a quarterly commitment fee calculated at a rate per annum equal to either: (1) 40% of the applicable margin, multiplied by the average daily amount of the undrawn commitment, or (2) 0.70% of the undrawn commitment, depending on the applicable 2015 SPL Credit Facility. The principal of the loans made under the 2015 SPL Credit Facilities must be repaid in quarterly installments, commencing with the earlier of June 30, 2020 and the last day of the first full calendar quarter after the completion date of Trains 1 through 5 of the Liquefaction Project. Scheduled repayments are based upon an 18-year amortization profile, with the remaining balance due upon the maturity of the 2015 SPL Credit Facilities.

The 2015 SPL Credit Facilities contain conditions precedent for borrowings, as well as customary affirmative and negative covenants. The obligations of SPL under the 2015 SPL Credit Facilities 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 and SPL Working Capital Facility.

Under the terms of the 2015 SPL Credit Facilities, SPL is required to hedge not less than 65% of the variable interest rate exposure of its projected outstanding borrowings, calculated on a weighted average basis in comparison to its anticipated draw of principal. Additionally, SPL may not make any distributions until substantial completion of Trains

1 and 2 of the Liquefaction Project has occurred, deposits are made into debt service reserve accounts and a debt service coverage ratio test of 1.25:1.00 is satisfied.

2013 SPL Credit Facilities

In May 2013, SPL entered into four credit facilities aggregating $5.9 billion (collectively, the “2013 SPL Credit Facilities”) to fund a portion of the costs of developing, constructing and placing into operation Trains 1 through 4 of the Liquefaction Project, which amended and restated the existing credit facility that was entered into in 2012 (the “2012 SPL Credit Facility”). In June 2015, the 2013 SPL Credit Facilities were replaced with the 2015 SPL Credit Facilities.

In March 2015, in conjunction with SPL's issuance of the 2025 SPL Senior Notes, SPL terminated approximately $1.8 billion of commitments under the 2013 SPL Credit Facilities. This termination and the replacement of the 2013 SPL Credit Facilities with the 2015 SPL Credit Facilities in June 2015 resulted in a write-off of debt issuance costs and deferred commitment fees associated with the 2013 SPL Credit Facilities of $96.3 million for the year ended December 31, 2015. The amendment and restatement of the 2012 SPL Credit Facility with the 2013 SPL Credit Facilities in May 2013 resulted in a write-off of debt issuance costs and deferred commitment fees associated with the 2012 SPL Credit Facility of $88.3 million during the year ended December 31, 2013.

CTPL Term Loan

CTPL has the $400.0 million CTPL Term Loan, which was used to fund modifications to the Creole Trail Pipeline and for general business purposes. The CTPL Term Loan matures in 2017 when the full amount of the outstanding principal obligations must be repaid. CTPL's loan may be repaid, in whole or in part, at any time without premium or penalty. As of December 31, 2015, CTPL had borrowed the full amount of $400.0 million available under the CTPL Term Loan. Borrowings under the CTPL Term Loan accrue interest at a variable rate per annum equal to, at CTPL's election, LIBOR or the base rate, plus the applicable margin. The applicable margin for LIBOR loans is 3.25%. Interest on LIBOR loans is due and payable at the end of each LIBOR period.

SPL Working Capital Facility

In September 2015, SPL entered into the $1.2 billion SPL Working Capital Facility, which replaced the $325.0 million SPL LC Agreement. 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 ("Letters of Credit"), 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, upon the completion of the debt financing of Train 6 of the Liquefaction Project, request an incremental increase in commitments of up to an additional $390 million. As of December 31, 2015, SPL had $1.1 billion of available commitments, $135.2 million aggregate amount of issued Letters of Credit, $15.0 million in Working Capital Loans and no Swing Line Loans or loans deemed made in connection with a draw upon a Letter of Credit ("LC Loans" and collectively with Working Capital Loans and Swing Line Loans, the "SPL Working Capital Facility Loans") outstanding under the SPL Working Capital Facility. As of December 31, 2014, SPL had issued letters of credit in an aggregate amount of $9.5 million, and no draws had been made upon any letters of credit issued under the SPL LC Agreement.

SPL Working Capital Facility Loans 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 SPL Working Capital Facility Loans is 1.75% per annum, and the applicable margin for base rate SPL Working Capital Facility Loans is 0.75% per annum. Interest on Swing Line Loans and LC Loans is due and payable on the date the loan becomes due. Interest on LIBOR Working Capital Loans is due and payable at the end of each applicable LIBOR period, and interest on base rate Working Capital Loans is due and payable at the end of each fiscal quarter. However, if such base rate Working Capital Loan is converted into a LIBOR Working Capital 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 incurred $27.5 million of debt issuance costs in connection with the SPL Working Capital Facility. 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 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 “LC Draw”) to be deemed an LC Loan, SPL is required to pay the full amount of the LC Draw on or prior to the business day following the notice of the LC Draw. An LC Draw accrues interest at an annual rate of 2.0% plus the base rate. As of December 31, 2015, no 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. LC Loans have a term of up to one year. 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 Swing Line Loan is made and (3) the first borrowing date for a Working Capital Loan or Swing Line Loan occurring at least three business days following the date the 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 and the 2015 SPL Credit Facilities.

Arrangement to Refinance Project Debt

In January 2016, we engaged 13 financial institutions to act as Joint Lead Arrangers, Mandated Lead Arrangers and other participants to assist in the structuring and arranging of up to approximately $2.8 billion of senior secured credit facilities. Proceeds from these new credit facilities are intended to be used by us to prepay $400.0 million of the CTPL Term Loan, to redeem or repay $1,665.5 million of the 2016 SPLNG Senior Notes and $420.0 million of the 2020 SPLNG Senior Notes, to pay associated transaction fees, expenses and make-whole amounts, if applicable, and for our general business purposes.

Sources and Uses of Cash

The following table summarizes the sources and uses of our cash and cash equivalents (in thousands) for the years ended December 31, 2015, 2014 and 2013. 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,		
	2015	2014	2013
Sources of cash and cash equivalents			
Proceeds from issuances of debt	$2,860,000	$2,584,500	$4,504,478
Use of restricted cash for the acquisition of property, plant and equipment	2,965,477	2,669,332	3,119,632
Operating cash flow	5,748	11,928	35,664
Proceeds from sale of partnership common and general partner units	—	—	375,897
Contributions to Creole Trail Pipeline Business from Cheniere, net	—	—	20,896
Total sources of cash and cash equivalents	5,831,225	5,265,760	8,056,567
Uses of cash and cash equivalents			
Investment in restricted cash	(2,690,364)	(2,303,763)	(4,173,959)
Property, plant and equipment, net	(2,912,080)	(2,645,553)	(3,120,643)
Debt issuance and deferred financing costs	(169,924)	(103,787)	(311,050)
Distributions to owners	(99,018)	(98,979)	(91,386)
Repayments of debt	—	(177,000)	(100,000)
Purchase of Creole Trail Pipeline Business, net	—	—	(313,892)
Other	(62,448)	(38,880)	(13,897)
Total uses of cash and cash equivalents	(5,933,834)	(5,367,962)	(8,124,827)
Net decrease in cash and cash equivalents	(102,609)	(102,202)	(68,260)
Cash and cash equivalents—beginning of period	248,830	351,032	419,292
Cash and cash equivalents—end of period	$146,221	$248,830	$351,032

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Proceeds from Issuances of Debt, Debt Issuance and Deferred Financing Costs and Repayments of Debt

In March 2015, SPL issued an aggregate principal amount of $2.0 billion of the 2025 SPL Senior Notes. In June 2015, SPL entered into the 2015 SPL Credit Facilities aggregating $4.6 billion, which terminated and replaced the 2013 SPL Credit Facilities, and borrowed $845.0 million under this facility during the year ended December 31, 2015. In September 2015, SPL entered into the $1.2 billion SPL Working Capital Facility which replaced the SPL LC Agreement, and borrowed $15.0 million in Working Capital Loans during the year ended December 31, 2015. Debt issuance and deferred financing costs in the year ended December 31, 2015 primarily relate to up-front fees paid upon the closing of these transactions.

In May 2014, SPL issued an aggregate principal amount of $2.0 billion of the 2024 SPL Senior Notes and an additional $0.5 billion principal amount of the 2023 SPL Senior Notes for total net proceeds of approximately $2.5 billion. Debt issuance costs in the year ended December 31, 2014 primarily relate to up-front fees paid upon the closing of these offerings.

During 2013, SPL issued an aggregate principal amount of $2.0 billion, before premium, of the 2021 SPL Senior Notes and$1.0 billion of each of the 2023 SPL Senior Notes and 2022 SPL Senior Notes. Net proceeds from those offerings were used to pay a portion of the capital costs incurred in connection with the construction of the Liquefaction Project. In May 2013, CTPL entered into the $400.0 million CTPL Term Loan, which was used to fund modifications to the Creole Trail Pipeline and for general business purposes. In June 2013, SPL borrowed $100.0 million under the 2013 SPL Credit Facilities. Debt issuance and deferred financing costs in the year ended December 31, 2013 primarily related to up-front fees paid by SPL upon the closing of the 2013 SPL Credit Facilities and the senior notes issued by SPL during the year.

Use of Restricted Cash for the Acquisition of Property, Plant and Equipment and Property, Plant and Equipment, net

During the years ended December 31, 2015, 2014 and 2013, we used $2,965.5 million, $2,669.3 million and $3,119.6 million, respectively, of restricted cash for investing activities to partially fund $2,912.1 million, $2,645.6 million and 3,120.6 million, respectively, of construction costs for Trains 1 through 5 of the Liquefaction Project. The costs associated with the construction of Trains 1 through 5 of the Liquefaction Project are capitalized as construction-in-process.

Operating Cash Flow

Cash provided by operations during the years ended December 31, 2015, 2014 and 2013 was $5.7 million, $11.9 million and $35.7 million, respectively. The decrease cash provided by operating activities from 2014 to 2015 primarily related to the timing of amounts paid to third parties for operating costs. The decrease in cash provided by operating activities from 2013 to 2014 was primarily a result of increased cash outflows during 2014 related to the settlement of interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2013 SPL Credit Facilities.

Proceeds from the Sale of Partnership Common and General Partner Units

In the year ended December 31, 2013, we received $375.9 million in proceeds from the sale of Cheniere Partners common and general partner units primarily related to the sale of 17.6 million common units to institutional investors in February 2013. We used the proceeds from this offering to purchase Cheniere's ownership interests in CTPL and Cheniere Pipeline GP Interests, LLC (collectively, "the Creole Trail Pipeline Business") described in our Note 3—Summary of Significant Accounting Policies of our Notes to Consolidated Financial Statements.

Contributions to Creole Trail Pipeline Business from Cheniere, net

Contributions to Creole Trail Pipeline Business from Cheniere, net relate to equity contributions provided by Cheniere to the entities owning the Creole Trail Pipeline that we purchased in May 2013. The acquisition has been accounted for as a transfer of net assets between entities under common control. During the year ended December 31, 2013, Cheniere contributed $20.9 million to the Creole Trail Pipeline entities that we acquired.

Investment in Restricted Cash

In the year ended December 31, 2015, we invested $2,690.4 million in restricted cash primarily related to the net proceeds from the 2025 SPL Senior Notes and borrowings under the 2015 SPL Credit Facilities and SPL Working Capital Facility, net of deferred financing costs. In the year ended December 31, 2014, we invested $2,303.8 million in restricted cash primarily related to the net proceeds from the notes issued by SPL during the year. In the year ended December 31, 2013, we invested $4,174.0 million in restricted cash primarily related to the net proceeds from the notes issued by SPL during the year and from the sale of common units by Cheniere Partners as described above.

Other

During the years ended December 31, 2015, 2014 and 2013, we used $62.4 million, $38.9 million and $13.9 million, respectively, of cash in other activities primarily as a result of payments made to a municipal water district for water system enhancements that will increase potable water supply to our Sabine Pass LNG terminal and investments made in unconsolidated entities.

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, 2015 and 2014:

				Total Distribution (in thousands)			
Date Paid	Period Covered by Distribution	Distribution Per Common Unit	Distribution Per Subordinated Unit	Common Units	Class B Units	Subordinated Units	General Partner Units
October 23, 2015	July 1 - September 30, 2015	$ 0.425	$ —	$24,260	$—	$ —	$495
August 14, 2015	April 1 - June 30, 2015	0.425	—	24,260	—	—	495
May 15, 2015	January 1 - March 31, 2015	0.425	—	24,259	—	—	495
February 13, 2015	October 1 - December 31, 2014	0.425	—	24,259	—	—	495
November 14, 2014	July 1 - September 30, 2014	$ 0.425	$ —	$24,259	$—	$ —	$495
August 14, 2014	April 1 - June 30, 2014	0.425	—	24,259	—	—	495
May 15, 2014	January 1 - March 31, 2014	0.425	—	24,259	—	—	495
February 14, 2014	October 1 - December 31, 2013	0.425	—	24,258	—	—	495

On January 22, 2016, we declared a $0.425 distribution per common unit and the related distribution to our general partner was paid on February 12, 2016 to owners of record as of February 1, 2016 for the period from October 1, 2015 to December 31, 2015.

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 or fees received from Cheniere Marketing under an amended and restated variable capacity rights agreement pursuant to which Cheniere Marketing is obligated to pay

Cheniere Investments 80% of the expected gross margin of each cargo of LNG that Cheniere Marketing arranges for delivery to the Sabine Pass LNG terminal. The ending of the subordination period and conversion of the subordinated units into common units will depend upon future business development.

In 2012 and 2013, we issued a new class of equity interests representing limited partner interests in us ("Class B units"), in connection with the development of the Liquefaction Project. The Class B units are not entitled to cash distributions, except in the event of our liquidation or a merger, consolidation or other combination of us with another person or the sale of all or substantially all of our assets. The Class B units are subject to conversion, mandatorily or at the option of the holders of the Class B units under specified circumstances, into a number of common units based on the then-applicable conversion value of the Class B units. On a quarterly basis beginning on the initial purchase date of the Class B units, the conversion value of the Class B units increases at a compounded rate of 3.5% per quarter, subject to an additional upward adjustment for certain equity and debt financings. The accreted conversion ratio of the class B units owned by Cheniere and Blackstone CQP Holdco was 1.62 and 1.59, respectively, as of December 31, 2015. We expect the Class B units to mandatorily convert into common units within 90 days of the substantial completion date of Train 3 of the Liquefaction Project, which we currently expect to occur before April 30, 2017. If the Class B units are not mandatorily converted by July 2019, the holders of the Class B units have the option to convert the Class B units into common units at that time. The holders of Class B units have a preference over the holders of the subordinated units in the event of our liquidation or a merger, consolidation or other combination of us with another person or the sale of all or substantially all of our assets.

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 thousands) in place as of December 31, 2015:

	Payments Due By Period (1)				
	Total	2016	2017 - 2018	2019 - 2020	Thereafter
Construction obligations (2)	$2,701,566	$1,543,647	$1,070,003	$87,916	$—
Purchase obligations (3)	1,522,360	375,164	515,814	372,110	259,272
Debt (4)	11,845,500	1,680,500	400,000	1,265,000	8,500,000
Interest payments (4)	4,109,954	699,912	1,142,682	1,132,230	1,135,130
Operating lease obligations (5)	40,976	2,620	4,439	4,253	29,664
Obligations to affiliates (6)	171,106	20,205	36,955	36,955	76,991
Other obligations	2,454	2,454	—	—	—
Total	$20,393,916	$4,324,502	$3,169,893	$2,898,464	$10,001,057

(1) Agreements in force as of December 31, 2015 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2015.

(2) Construction obligations primarily relate to the EPC contracts for Trains 1 through 5 of the Liquefaction Project. The estimated remaining costs pursuant to our EPC contracts as of December 31, 2015 is included. A discussion of these obligations can be found at Note 13—Commitments and Contingencies of our Notes to Consolidated Financial Statements.

(3) Purchase obligations consists of contracts for which conditions precedent have been met, and primarily relate to natural gas supply, transportation and storage services, as well as maintenance contracts for the Liquefaction Project. As project milestones and other conditions precedent are achieved, our obligations are expected to increase accordingly.

(4) Based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2015. See Note 10—Debt of our Notes to Consolidated Financial Statements.

(5) Operating lease obligations primarily relate to land sites related to the Sabine Pass LNG terminal. A discussion of these obligations can be found in Note 12—Leases of our Notes to Consolidated Financial Statements.

(6) Obligations arising through intercompany service agreements include only fixed fees and do not include variable fees. A discussion of these obligations can be found in Note 11—Related Party Transactions of our Notes to Consolidated Financial Statements.

In addition, in the ordinary course of business, we maintain letters of credit and have certain cash restricted in support of certain performance obligations of our subsidiaries. As of December 31, 2015, we had $135.2 million aggregate amount of issued Letters of Credit under the SPL Working Capital Facility and $288.3 million of current and non-current restricted cash. For more information, see Note 4—Restricted Cash of our Notes to Consolidated Financial Statements.

Results of Operations

2015 vs. 2014

Our consolidated net loss decreased $91.1 million, from $410.0 million of consolidated net loss in the year ended December 31, 2014, to $318.9 million of consolidated net loss in the year ended December 31, 2015. The decrease in consolidated net loss was primarily a result of decreased derivative loss, net, decreased operating and maintenance expense and decreased loss on early extinguishment of debt, partially offset by increased general and administrative expense ("G&A Expense") (including affiliate amounts).

Derivative loss, net decreased $77.7 million, from $119.4 million in the year ended December 31, 2014, to $41.7 million in the year ended December 31, 2015. The higher derivative loss recognized during the year ended December 31, 2014 was attributable to a decrease in long-term LIBOR during that period, whereas the movement in long-term LIBOR had a minimal effect on derivative loss for the year ended December 31, 2015 as a result of a lower notional amount of interest rate derivatives. Instead of movement in long-term LIBOR rates, the $41.7 million derivative loss recognized during the year ended December 31, 2015 was primarily attributable to the loss recognized in March 2015 upon the termination of interest rate swaps associated with approximately $1.8 billion of commitments that were terminated under the 2013 SPL Credit Facilities.

Operating and maintenance expense decreased $31.9 million in the year ended December 31, 2015, as compared to the year ended December 31, 2014, due to a $32.2 million increase in fair value for our natural gas purchase agreements recorded during the third quarter of 2015, which we recognized following the completion and placement into service of certain modifications to the Creole Trail Pipeline and the resulting development of a market for physical gas delivery at locations specified in a portion of our natural gas purchase agreements. Excluding this amount, operating and maintenance expense would have been $63.1 million during the year ended December 31, 2015, which is comparable to $62.8 million incurred during the year ended December 31, 2014.

Loss on early extinguishment of debt decreased $18.0 million, from $114.3 million in the year ended December 31, 2014, to $96.3 million in the year ended December 31, 2015. Loss on early extinguishment of debt during the year ended December 31, 2015 was attributable to the write-off of debt issuance costs and deferred commitment fees in connection with the termination of approximately $1.8 billion of commitments under the 2013 SPL Credit Facilities in March 2015 and the replacement of the 2013 SPL Credit Facilities with the 2015 SPL Credit Facilities in June 2015. Loss on early extinguishment of debt during the year ended December 31, 2014 was attributable to the write-off of debt issuance costs in connection with the early extinguishment of $2.1 billion of commitments under the 2013 SPL Credit Facilities in May 2014.

Partially offsetting the above decreases in expenses, G&A Expense (including affiliate amounts) increased $22.2 million in the year ended December 31, 2015, as compared to the year ended December 31, 2014, primarily due to costs of services provided by Cheniere pursuant to an information technology services agreement.

There was no significant change to interest expense, net of amounts capitalized in the year ended December 31, 2015, as compared to the year ended December 31, 2014, primarily as a result of our capitalization of interest costs incurred which were directly related to the construction of the first five Trains of the Liquefaction Project. For the years ended December 31, 2015 and 2014, we incurred $707.7 million and $580.2 million of total interest cost, respectively, of which we capitalized and deferred $523.1 million and $403.2 million, respectively.

2014 vs. 2013

Our consolidated net loss increased $151.9 million, from $258.1 million in the year ended December 31, 2013, to $410.0 million in the year ended December 31, 2014. The increase in net loss was primarily a result of decreased derivative gain, net, which was partially offset by decreased general and administrative expense—affiliate and decreased loss on early extinguishment of debt.

Derivative gain, net decreased $202.2 million, from $82.8 million gain in the year ended December 31, 2013 to $119.4 million loss in the year ended December 31, 2014, primarily as a result of a decrease in long-term LIBOR during the year ended December 31, 2014, as compared to an increase in long-term LIBOR during the year ended December 31, 2013, and the early settlement of interest rate swaps in connection with the early extinguishment of a portion of the 2013 SPL Credit Facilities in May 2014.

General and administrative expense—affiliate decreased $28.5 million in the year ended December 31, 2014, as compared to the year ended December 31, 2013, primarily as a result of decreased costs incurred to manage the construction of Trains 1 through 4 of the Liquefaction Project, which resulted from a management services agreement in which we are required to pay a monthly fee based upon the capital expenditures incurred in the previous month for Trains 1 through 4 until substantial completion of each Train. Loss on early extinguishment of debt decreased $17.2 million in the year ended December 31, 2014, as compared to the year ended December 31, 2013, due to the write-off of debt issuance costs in connection with the early extinguishment of $2.1 billion of commitments under the 2013 SPL Credit Facilities in May 2014, as compared to the write-off of debt issuance costs and deferred commitment fees in connection with the early extinguishment of a portion of the commitments under the 2012 SPL Credit Facility in April 2013 and under the 2013 SPL Credit Facilities in November 2013.

There was no significant change to interest expense, net of amounts capitalized in the year ended December 31, 2014, as compared to the year ended December 31, 2013, primarily as a result of our capitalization of interest costs incurred which were directly related to the construction of the first four Trains of the Liquefaction Project. For the years ended December 31, 2014 and 2013, we incurred $580.2 million and $414.0 million of total interest cost, respectively, of which we capitalized and deferred $403.2 million and $235.6 million, respectively.

Off-Balance Sheet Arrangements

As of December 31, 2015, 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 value of properties, plant and equipment, asset retirement obligations ("AROs") and fair values. 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

When necessary or required by GAAP, we estimate fair value for derivatives, long-lived assets for impairment testing, initial measurements of AROs and financial instruments that require fair value disclosure, including debt. When we are required to measure fair value and there is not a market-observable price for the asset or liability or for a similar asset or liability, we use the cost, income or market valuation approaches depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach is based on management's best assumptions regarding expectations of projected cash flows, and discounts the expected cash flows using a commensurate risk-adjusted discount rate. The market approach is based on management's best assumptions regarding prices and other relevant information from market transactions involving comparable assets. Such evaluations involve significant judgment and the results are based on expected future events or conditions, such as sales prices, estimates of future LNG production, development, construction and operating costs and the timing thereof, future net cash flows, economic and regulatory climates and other factors, most of which are often outside of management's control. However, assumptions used reflect a market participant's view of long-term prices, costs and other factors, and are consistent with assumptions used in our business plans and investment decisions.

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 techniques.

Our derivative instruments consist of financial natural gas derivative contracts transacted in an over-the-counter market, index-based physical natural gas contracts and interest rate swaps. Valuation of our financial natural gas derivative contracts is determined using observable commodity price curves and other relevant data. Valuation of our index-based physical natural gas contracts is developed through the use of internal models which are impacted by inputs that are unobservable in the marketplace, market transactions and other relevant data. We value our interest rate swaps using observable inputs including interest rate curves, risk adjusted discount rates, credit spreads and other relevant data.

Gains and losses on derivative instruments are recognized currently 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 commodity prices and interest rates change.

Impairment of Long-Lived Assets

A long-lived asset, including an intangible asset, is evaluated for potential impairment whenever events or changes in circumstances indicate that its carrying value may not be recoverable. Recoverability generally is determined by comparing the carrying value of the asset to the expected undiscounted future cash flows of the asset. If the carrying value of the asset is not recoverable, the amount of impairment loss is measured as the excess, if any, of the carrying value of the asset over its estimated fair value. We use a variety of fair value measurement techniques when market information for the same or similar assets does not exist. Projections of future operating results and cash flows may vary significantly from results. Management reviews its estimates of cash flows on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment.

Recent Accounting Standards

For descriptions of recently issued accounting standards, see Note 16—Recent Accounting Standards of our Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Cash Investments

We have cash investments that we manage based on internal investment guidelines that emphasize liquidity and preservation of capital. Such cash investments are stated at historical cost, which approximates fair market value on our Consolidated Balance Sheets.

Marketing and Trading Commodity Price Risk

We have entered into commodity derivatives consisting of natural gas purchase agreements to secure natural gas feedstock for 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 basis price for natural gas for each delivery location. As of December 31, 2015, we estimated the fair value of the Liquefaction Supply Derivatives to be $32.5 million. Based on actual derivative contractual volumes, a 10% increase or decrease in the underlying basis price would have resulted in a change in the fair value of the Liquefaction Supply Derivatives of $0.9 million as of December 31, 2015, compared to $0.4 million as of December 31, 2014. The increase in the effect of change in the underlying basis price was due to a $32.2 million increase in fair value for our natural gas purchase agreements recorded during the third quarter of 2015, which we recognized following the completion and placement into service of certain modifications to the Creole Trail Pipeline and the resulting development of a market for physical gas delivery at locations specified in a portion of our natural gas purchase agreements. See Note 7—Derivative Instruments for additional details about our derivative instruments.

Interest Rate Risk

We have entered into interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2015 SPL Credit Facilities (“Interest Rate Derivatives”). In order to test the sensitivity of the fair value of the Interest Rate Derivatives to changes in interest rates, management modeled a 10% change in the forward 1-month LIBOR curve across the full 7-year term of the Interest Rate Derivatives. This 10% change in interest rates would have resulted in a change in the fair value of our Interest Rate Derivatives of $3.1 million as of December 31, 2015, compared to $16.5 million as of December 31, 2014. The decrease in the effect of change in interest rates was due to lower notional amounts of Interest Rate Derivatives outstanding and a decrease in the forward 1-month LIBOR curve during the year ended December 31, 2015.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

CHENIERE ENERGY PARTNERS, L.P.

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

Management’s Report on Internal Control Over Financial Reporting

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

Based on our assessment, we have concluded that Cheniere Partners maintained effective internal control over financial reporting as of December 31, 2015, 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, 2015, 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/ Neal A. Shear	By: /s/ Michael J. Wortley
Neal A. Shear	Michael J. Wortley
Interim Chief Executive Officer	Senior Vice President and Chief Financial Officer
(Principal Executive Officer)	(Principal Financial Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Cheniere Energy Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive loss, partners' equity, and cash flows for each of the years in the two-year period ended December 31, 2015. In connection with our audits of the consolidated financial statements, we also have audited financial statement schedule I for each of the years in the two-year period ended December 31, 2015. These consolidated financial statements and financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Cheniere Energy Partners, L.P. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule for each of the years in the two-year period ended December 31, 2015, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Cheniere Energy Partners, L.P.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 18, 2016, expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP
KPMG LLP

Houston, Texas
February 18, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited Cheniere Energy Partners, L.P.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Cheniere Energy Partners, L.P.'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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 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.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Cheniere Energy Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Cheniere Energy Partners, L.P. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive loss, partners' equity, and cash flows for each of the years in the two-year period ended December 31, 2015, and our report dated February 18, 2016 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
KPMG LLP

Houston, Texas

February 18, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated statements of operations, comprehensive loss, partners' equity, and cash flows of Cheniere Energy Partners, L.P. and subsidiaries for the year ended December 31, 2013. Our audits also included the financial statement schedule for the year ended December 31, 2013 listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audit.
We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated results of operations and cash flows of Cheniere Energy Partners, L.P. and subsidiaries for the year ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ ERNST & YOUNG LLP
Ernst & Young LLP

Houston, Texas
February 21, 2014

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands, except unit data)

	December 31, 2015	2014
ASSETS		
Current assets		
Cash and cash equivalents	$146,221	$248,830
Restricted cash	274,557	195,702
Accounts and interest receivable	742	333
Accounts receivable—affiliate	1,271	3,651
Advances to affiliate	39,836	27,323
Inventory	16,667	7,786
Other current assets	11,828	2,895
Other current assets—affiliate	2,353	—
Total current assets	493,475	486,520
Non-current restricted cash	13,650	544,465
Property, plant and equipment, net	11,931,602	8,978,356
Debt issuance costs, net	295,265	241,909
Non-current derivative assets	30,304	11,744
Other non-current assets	200,013	124,521
Other non-current assets—affiliate	32,018	—
Total assets	$12,996,327	$10,387,515
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accounts payable	$16,407	$8,598
Accrued liabilities	224,292	136,578
Current debt, net	1,676,197	—
Due to affiliates	115,123	18,952
Deferred revenue	26,669	26,655
Deferred revenue—affiliate	717	708
Derivative liabilities	6,430	23,247
Other current liabilities	—	18
Total current liabilities	2,065,835	214,756
Long-term debt, net	10,178,681	8,991,333
Non-current deferred revenue	9,500	13,500
Other non-current liabilities	3,059	2,452
Other non-current liabilities—affiliate	26,321	34,745
Commitments and contingencies (see Note 13)		
Partners' equity		
Common unitholders' interest (57.1 million units issued and outstanding at December 31, 2015 and 2014)	305,747	495,597
	(37,429)	(38,216)

Class B unitholders' interest (145.3 million units issued and outstanding at December 31, 2015 and 2014)		
Subordinated unitholders' interest (135.4 million units issued and outstanding at December 31, 2015 and 2014)	428,035	648,414
General partner's interest (2% interest with 6.9 million units issued and outstanding at December 31, 2015 and 2014)	16,578	24,934
Total partners' equity	712,931	1,130,729
Total liabilities and partners' equity	$12,996,327	$10,387,515

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit data)

	Year Ended December 31,		
	2015	2014	2013
Revenues			
Revenues	$265,637	$265,740	$265,251
Revenues—affiliate	4,391	2,958	2,940
Total revenues	270,028	268,698	268,191
Operating costs and expenses			
Operating and maintenance expense	30,940	62,819	59,300
Operating and maintenance expense—affiliate	29,379	21,115	29,304
Depreciation and amortization expense	65,704	58,601	57,486
Development expense	2,850	9,319	11,322
Development expense—affiliate	722	1,153	1,402
General and administrative expense	15,079	13,807	11,570
General and administrative expense—affiliate	122,312	101,369	129,836
Total operating costs and expenses	266,986	268,183	300,220
Income (loss) from operations	3,042	515	(32,029)
Other income (expense)			
Interest expense, net of amounts capitalized	(184,600)	(177,032)	(178,400)
Loss on early extinguishment of debt	(96,273)	(114,335)	(131,576)
Derivative gain (loss), net	(41,722)	(119,401)	82,791
Other income	662	217	1,097
Total other expense	(321,933)	(410,551)	(226,088)
Net loss	$(318,891)	$(410,036)	$(258,117)
Net loss attributable to the Creole Trail Pipeline Business	—	—	(18,150)
Net loss attributable to partners	$(318,891)	$(410,036)	$(239,967)
Basic and diluted net income (loss) per common unit	$(0.43)	$(0.89)	$(0.03)
Weighted average number of common units outstanding used for basic and diluted net income (loss) per common unit calculation	57,081	57,079	54,235

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS
(in thousands)

	Year Ended December 31,		
	2015	2014	2013
Net loss	$(318,891)	$(410,036)	$(258,117)
Other comprehensive income (loss)			
Loss on settlements of interest rate cash flow hedges retained in other comprehensive income	—	—	(30)
Change in fair value of interest rate cash flow hedges	—	—	21,297
Losses reclassified into earnings as a result of discontinuance of cash flow hedge accounting	—	—	5,973
Total other comprehensive income (loss)	—	—	27,240
Comprehensive loss	$(318,891)	$(410,036)	$(230,877)

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 thousands)

	Common Unitholders' Interest		Class B Unitholders' Interest		Subordinated Unitholder's Interest		General Partner's Interest		Accumulated Other Comprehensive Loss	Creole Trail Pipeline Business Equity	Total Partners' Equity
	Units	Amount	Units	Amount	Units	Amount	Units	Amount			
Balance at December 31, 2012	39,488	$448,412	133,333	$(37,342)	135,384	$949,482	6,290	$29,496	$(27,240)	$517,170	$1,879,
Net loss	—	(67,263)	—	—	—	(167,905)	—	(4,799)	—	(18,150)	(258,11
Contributions to Creole Trail Pipeline Business from Cheniere, net	—	—	—	—	—	—	—	—	—	20,896	20,896
Acquisition of the Creole Trail Pipeline Business	—	—	—	—	—	—	—	—	—	(519,916)	(519,91
Excess of acquired assets over the purchase price	—	2,022	—	—	—	22,880	—	1,124	—	—	26,026
Issuance of Class B units associated with acquisition of Creole Trail Pipeline Business	—	—	12,000	179,126	—	—	—	—	—	—	179,126
Sale of common and general partner units	17,590	364,775	—	—	—	—	604	11,122	—	—	375,897
Distributions	—	(89,558)	—	—	—	—	—	(1,828)	—	—	(91,386
Interest rate cash flow hedges	—	—	—	—	—	—	—	—	27,240	—	27,240
Beneficial conversion feature of Class B units	—	53,383	—	(180,000)	—	126,617	—	—	—	—	—
Balance at December 31, 2013	57,078	711,771	145,333	(38,216)	135,384	931,074	6,894	35,115	—	—	1,639,7
Net loss	—	(119,175)	—	—	—	(282,660)	—	(8,201)	—		(410,03
Distributions	—	(97,035)	—	—	—	—	—	(1,980)	—	—	(99,015
Issuance of common units as compensation to non-management	2	36	—	—	—	—	—	—	—	—	36

directors											
Balance at December 31, 2014	57,080	495,597	145,333	(38,216)	135,384	648,414	6,894	24,934	—	—	1,130,7
Net loss	—	(92,688)	—	—	—	(219,825)	—	(6,378)	—		(318,89
Distributions	—	(97,038)	—	—	—	—	—	(1,980)	—	—	(99,018
Issuance of common units as compensation to non-management directors	4	109	—	—	—	—	—	2	—	—	111
Amortization of beneficial conversion feature of Class B units	—	(233)	—	787	—	(554)	—	—	—	—	—
Balance at December 31, 2015	57,084	$305,747	145,333	$(37,429)	135,384	$428,035	6,894	$16,578	$—	$—	$712,9

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 thousands)

	Year Ended December 31,		
	2015	2014	2013
Cash flows from operating activities			
Net loss	$(318,891)	$(410,036)	$(258,117)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Non-cash LNG inventory write-downs	17,537	24,461	26,900
Depreciation and amortization expense	65,704	58,601	57,486
Amortization of debt issuance costs and discount	12,174	14,264	14,948
Loss on early extinguishment of debt	96,273	114,335	131,576
Total (gains) losses on derivatives, net	7,154	117,701	(84,296)
Net cash used for settlement of derivative instruments	(41,398)	(21,581)	579
Other	85	15	—
Changes in restricted cash for certain operating activities	176,847	148,972	171,345
Changes in operating assets and liabilities:			
Accounts and interest receivable	259	(293)	4
Accounts receivable—affiliate	1,248	(503)	(1,083)
Advances to affiliate	(12,513)	(12,586)	(9,281)
Inventory	(25,037)	(19,008)	(30,903)
Accounts payable and accrued liabilities	(996)	3,949	(2,384)
Due to affiliates	14,882	(15,842)	26,091
Deferred revenue	(3,986)	(3,938)	(3,947)
Other, net	(12,010)	(4,236)	(7,632)
Other, net—affiliate	28,416	17,653	4,378
Net cash provided by operating activities	5,748	11,928	35,664
Cash flows from investing activities			
Property, plant and equipment, net	(2,912,080)	(2,645,553)	(3,120,643)
Use of restricted cash for the acquisition of property, plant and equipment	2,965,477	2,669,332	3,119,632
Purchase of Creole Trail Pipeline Business, net	—	—	(313,892)
Other	(62,448)	(38,880)	(13,897)
Net cash used in investing activities	(9,051)	(15,101)	(328,800)
Cash flows from financing activities			
Proceeds from issuances of debt	2,860,000	2,584,500	4,504,478
Repayments of debt	—	(177,000)	(100,000)
Debt issuance and deferred financing costs	(169,924)	(103,787)	(311,050)
Investment in restricted cash	(2,690,364)	(2,303,763)	(4,173,959)
Proceeds from sale of partnership common and general partner units	—	—	375,897
Contributions to Creole Trail Pipeline Business from Cheniere, net	—	—	20,896
Distributions to owners	(99,018)	(98,979)	(91,386)
Net cash provided by (used in) financing activities	(99,306)	(99,029)	224,876
Net decrease in cash and cash equivalents	(102,609)	(102,202)	(68,260)

Cash and cash equivalents—beginning of period	248,830	351,032	419,292
Cash and cash equivalents—end of period	$146,221	$248,830	$351,032

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—ORGANIZATION AND NATURE OF OPERATIONS

We are a publicly traded Delaware limited partnership (NYSE MKT: CQP) formed by Cheniere. Through our wholly owned subsidiary, SPLNG, we own and operate the regasification facilities at the Sabine Pass LNG terminal located on the Sabine-Neches Waterway less than four miles from the Gulf Coast. The Sabine Pass LNG terminal includes existing infrastructure of five LNG storage tanks with capacity of approximately 16.9 Bcfe, two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. We are developing and constructing natural gas liquefaction facilities (the "Liquefaction Project") at the Sabine Pass LNG terminal adjacent to the existing regasification facilities through our wholly owned subsidiary, SPL. We are constructing five Trains and developing a sixth Train, each of which is expected to have a nominal production capacity of approximately 4.5 mtpa of LNG. We also own a 94-mile pipeline that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines (the "Creole Trail Pipeline") through our wholly owned subsidiary, CTPL.

As of December 31, 2015, Cheniere owned 100% of our general partner interest and 80.1% of Cheniere Holdings, which owned 12.0 million of our common units, 45.3 million of our Class B units and 135.4 million of our subordinated units.

NOTE 2—UNITHOLDERS' EQUITY

The common units, Class B 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 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, 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. The higher percentages range from 15% to 50%.

During 2012, Blackstone CQP Holdco and Cheniere completed their purchases of a new class of equity interests representing limited partner interests in us ("Class B units") for total consideration of $1.5 billion and $500.0 million, respectively. Proceeds from the financings were used to fund a portion of the costs of developing, constructing and placing into service the first two Trains of the Liquefaction Project. In May 2013, Cheniere purchased an additional 12.0 million Class B units for consideration of $180.0 million in connection with our acquisition of CTPL and Cheniere Pipeline GP Interests, LLC. In 2013, Cheniere formed Cheniere Holdings to hold its limited partner interests in us. The Class B units are subject to conversion, mandatorily or at the option of the Class B unitholders under specified circumstances, into a number of common units based on the then-applicable conversion value of the Class B units. The Class B units are not entitled to cash distributions except in the event of our liquidation or a merger, consolidation or other combination of us with another person or the sale of all or substantially all of our assets. On a quarterly basis beginning on the date of the initial purchase date of the Class B units, the conversion value of the Class B units increases at a compounded rate of 3.5% per quarter, subject to additional upward adjustment for certain equity and debt financings. The accreted conversion ratio of the Class B units owned by Cheniere Holdings and Blackstone CQP Holdco was 1.62 and 1.59, respectively, as of December 31, 2015. We expect the Class B units to mandatorily convert into common units within 90 days of the substantial completion date of Train 3 of the Liquefaction Project, which we currently expect to occur before April 30, 2017. If the Class B units are not mandatorily converted by July 2019, the holders of the Class B units have the option to convert the Class B units into common units at that time.

NOTE 3—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Our Consolidated Financial Statements were prepared in accordance with GAAP. The Consolidated Financial Statements include the accounts of Cheniere Energy Partners, L.P. and its majority owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

In May 2013, we completed the acquisition of Cheniere's ownership interests in CTPL and Cheniere Pipeline GP Interests, LLC (collectively, "the Creole Trail Pipeline Business"), thereby providing us with ownership of a 94-mile pipeline interconnecting the Sabine Pass LNG terminal with a large number of interstate pipelines. We acquired the Creole Trail Pipeline Business for $480.0 million and reimbursed Cheniere $13.9 million for certain expenditures incurred prior to the closing date. Concurrent with the Creole Trail Pipeline Business acquisition closing, we issued 12.0 million Class B units to Cheniere for aggregate consideration of $180.0 million pursuant to a unit purchase agreement with Cheniere Class B Units Holdings, LLC, a wholly owned subsidiary of Cheniere. As a result of the two transactions, we paid Cheniere net cash of $313.9 million.

These Consolidated Financial Statements include our accounts and the assets, liabilities and operations of the Creole Trail Pipeline Business. The effect of including the prior results of the Creole Trail Pipeline Business is reported as net loss attributable to Creole Trail Pipeline Business in our Consolidated Statement of Operations and Creole Trail Pipeline Business equity in our Consolidated Balance Sheets and Consolidated Statements of Partners' Equity. This purchase has been accounted for as a transfer of net assets between entities under common control.

We recognize transfers of net assets between entities under common control at Cheniere's historical basis in the net assets sold. In addition, transfers of net assets between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information. The difference between the purchase price and Cheniere's basis in the net assets sold, if any, is recognized as an adjustment to partners' equity.

Subsequent to the Creole Trail Pipeline Business acquisition, we control CTPL's operating and financial decisions and policies and have consolidated CTPL in our Financial Statements. Our Consolidated Financial Statements and all other financial information included in this report assume that our acquisition of the Creole Trail Pipeline Business from Cheniere had occurred at the date when the Creole Trail Pipeline Business met the accounting requirements for entities under common control (the date of our inception since both we and the Creole Trail Pipeline Business were formed by Cheniere). Net income (loss) attributable to the Creole Trail Pipeline Business for periods prior to the acquisition is not allocated to the common units for purposes of calculating net income (loss) per common unit. See Note 15—Net Income (Loss) Per Common Unit for an adjusted net loss per common unit that includes pre-acquisition date net losses of the Creole Trail Pipeline Business.

Certain reclassifications have been made to conform prior period information to the current presentation. The reclassifications had no effect on our overall consolidated financial position, operating results or cash flows.

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 the value of property, plant and equipment, collectability of accounts receivable, derivative instruments, asset retirement obligations (“AROs”) and fair value measurements. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value

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 techniques 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 other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. 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 commodity derivatives and interest rate derivatives as disclosed in Note 7—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 10—Debt, are based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments. Non-financial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a business combination, intangible assets and AROs.

Revenue Recognition

LNG regasification capacity reservation fees are recognized as revenue over the term of the respective TUAs. Advance capacity reservation fees are initially deferred and amortized over a 10-year period as a reduction of a customer's regasification capacity reservation fees payable under its TUA. Under each of these TUAs, SPLNG is entitled to retain 2% of LNG delivered for each customer's account at the Sabine Pass LNG terminal, which is recognized as revenues as SPLNG performs the services set forth in each customer's TUA.

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 restricted as to usage or withdrawal and have been presented separately from cash and cash equivalents on our Consolidated Balance Sheets.

Amounts that are designated as restricted cash are contractually restricted as to usage or withdrawal and will not become available to us as cash and cash equivalents. For these amounts, we have presented increases and decreases separately from increases and decreases in cash and cash equivalents in our Consolidated Statements of Cash Flows. These amounts that represent non-cash transactions within our Consolidated Statements of Cash Flows present the effect of sources and uses of restricted cash as they relate to the changes to assets and liabilities in our Consolidated Balance Sheets. Restricted cash is presented on a gross basis within each of those categories so as to reconcile the change in non-cash activity that occurs on the balance sheet from period to period.

Inventory

Inventory is recorded at weighted average cost and is subject to lower of cost or market ("LCM") adjustments at the end of each period. Our LCM adjustments primarily related to LNG inventory purchased to maintain the cryogenic readiness of the regasification facilities at the Sabine Pass LNG terminal that are recorded in operating and maintenance expense on our Consolidated Statements of Operations. Recoveries of losses resulting from interim period LCM adjustments are recorded when market price recoveries occur on the same inventory in the same fiscal year. These recoveries are recognized as gains in later interim periods with such gains not exceeding previously recognized losses.

During the years ended December 31, 2015, 2014 and 2013, we recognized $17.5 million, $24.5 million and $26.9 million, respectively, as operating and maintenance expense as a result of LCM adjustments to our LNG inventory.

Accounting for LNG Activities

Generally, we begin capitalizing the costs of our LNG terminals and related pipelines 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 front-end engineering and design work, costs of securing necessary regulatory approvals and other preliminary investigation and development activities related to our LNG terminals and related pipelines.

Generally, costs that are capitalized prior to a project meeting the criteria otherwise necessary for capitalization include: land and lease option costs that are capitalized as property, plant and equipment 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 lease is obtained, the costs are expensed.

We capitalize interest and other related debt costs during the construction period of our LNG terminal and related pipeline. Upon commencement of operations, capitalized interest, as a component of the total cost, will be amortized over the estimated useful life of the asset.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Expenditures for construction activities, major renewals and betterments that extend the useful life of an asset are capitalized, while expenditures for maintenance and repairs and general and administrative activities are charged to expense as incurred. Interest costs incurred on debt obtained for the construction of property, plant and equipment are capitalized as construction-in-process over the construction period or related debt term, whichever is shorter. 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 other operating costs and expenses.

Management tests property, plant and equipment for impairment whenever events or changes in circumstances have indicated that the carrying amount of property, plant and equipment might not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets for purposes of assessing recoverability. Recoverability generally is determined by comparing the carrying value of the asset to the expected undiscounted future cash flows of the asset. If the carrying value of the asset is not recoverable, the amount of impairment loss is measured as the excess, if any, of the carrying value of the asset over its estimated fair value. We have recorded no impairments related to property, plant and equipment for 2015, 2014 or 2013.

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.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

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 pipelines. Under regulatory rate practices, we generally are permitted to recover AFUDC, and a fair return thereon, through our rate base after our natural gas pipelines are placed in service.

Derivative Instruments

We use derivative instruments to hedge our exposure to cash flow variability from commodity price and interest rate 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 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 current earnings, unless we elect to apply hedge accounting and meet specified criteria, including completing contemporaneous hedge documentation. We did not have any derivative instruments designated as cash flow hedges as of December 31, 2015 and 2014.

In the past, we elected cash flow hedge accounting for derivatives that we used to hedge the exposure to volatility in floating-rate interest payments. Changes in fair value of derivative instruments designated as cash flow hedges, to the extent the hedge was effective, were recognized in accumulated other comprehensive loss on our Consolidated Balance Sheets. We reclassified gains and losses on the hedges from accumulated other comprehensive loss into interest expense in our Consolidated Statements of Operations as the hedged item was recognized. Any change in the fair value resulting from ineffectiveness was recognized immediately as derivative gain (loss) on our Consolidated Statements of Operations. We used regression analysis to determine whether we expected a derivative to be highly effective as a cash flow hedge, prior to electing hedge accounting and also to determine whether all derivatives designated as cash flow hedges had been effective. We performed these effectiveness tests prior to designation for all new hedges and on a quarterly basis for all existing hedges. We calculated the actual amount of ineffectiveness on our cash flow hedges using the "dollar offset" method, which compared changes in the expected cash flows of the hedged transaction to changes in the value of expected cash flows from the hedge. We discontinued hedge accounting when our effectiveness tests indicated that a derivative was no longer highly effective as a hedge; when the derivative expired or was sold, terminated or exercised; when the hedged item matured, was sold or repaid; or when we determined that the occurrence of the hedged forecasted transaction was not probable. When we discontinued hedge accounting but continued to hold the derivative, prospective changes in fair value of the derivative instrument were recorded in income. Once we concluded that the hedged forecasted transaction became probable of not occurring, the amount remaining in accumulated other comprehensive loss pertaining to the previously designated derivatives was reclassified out of accumulated other comprehensive loss and into income.

See Note 7—Derivative Instruments for additional details about our derivative instruments.

Concentration of Credit Risk

Financial instruments that potentially subject us to a concentration of credit risk consist principally of cash and cash equivalents and restricted cash. 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. 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 as other current asset. 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.

SPLNG has entered into two long-term TUAs with unaffiliated third parties for regasification capacity at the Sabine Pass LNG terminal. SPLNG is dependent on the respective counterparties' creditworthiness and their willingness to perform under

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

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 AA.

SPL has entered into six fixed price 20-year SPAs with six unaffiliated third parties. SPL is dependent on the respective counterparties’ creditworthiness and their willingness to perform under their respective SPAs.

Debt

Our debt consists of current and long-term secured 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 Balance Sheet at par value adjusted for unamortized discount or premium. Discounts, premiums and costs directly related to the issuance of debt are amortized over the life of the debt and are recorded in interest expense, net using the effective interest method. Gains and losses on the extinguishment of debt are recorded in gains and losses on the extinguishment of debt on our Consolidated Statements of Operations.

Debt issuance costs consist primarily of arrangement fees, professional fees, legal fees and printing costs. These costs are recorded as debt issuance costs on our Consolidated Balance Sheets and are being amortized to interest expense or property, plant and equipment over the term of the related debt facility. Upon early retirement of debt or amendment to a debt agreement, certain fees are written off to loss on early extinguishment of debt.

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. Our recognition of AROs is described below.

Currently, the Sabine Pass LNG terminal is our only constructed and operating 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 zero. Therefore, we have not recorded an ARO associated with the Sabine Pass LNG terminal.

Currently, the Creole Trail Pipeline is our only constructed and operating natural gas 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. Therefore, we have concluded that due to advanced technology associated with current natural gas pipelines and our intent to operate the Creole Trail Pipeline as long as supply and demand for natural gas exists in the United States, we have not recorded an ARO associated with the Creole Trail Pipeline.

Income Taxes

We are not subject to federal, state or foreign income taxes, as the partners are taxed individually on their allocable share of taxable income. At December 31, 2015, the tax basis of our assets and liabilities was $212.8 million less than the reported amounts of our assets and liabilities. See Note 11—Related Party Transactions for details about income taxes under our tax sharing agreements.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Business Segment

Our LNG terminal business is our only operating business segment in which separate financial information is produced and evaluated by our chief operating decision maker in deciding how to allocate resources. Our LNG terminal business segment consists of the operational regasification and pipeline facilities at the Sabine Pass LNG terminal and the adjacent Liquefaction Project. The Sabine Pass LNG terminal includes existing infrastructure of five LNG storage tanks with capacity of approximately 16.9 Bcfe, two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters, vaporizers with regasification capacity of approximately 4.0 Bcf/d and pipeline facilities (including the Creole Trail Pipeline) interconnecting the Sabine Pass LNG terminal with a number of large interstate pipelines. The Liquefaction Project is adjacent to the existing regasification facilities at the Sabine Pass LNG terminal.

NOTE 4—RESTRICTED CASH

Restricted cash consists of funds that are contractually restricted as to usage or withdrawal and have been presented separately from cash and cash equivalents on our Consolidated Balance Sheets. Restricted cash includes the following:

SPLNG Senior Notes Debt Service Reserve

SPLNG, our wholly owned subsidiary, has consummated private offerings of an aggregate principal amount of $1.7 billion, before discount, of 7.50% Senior Secured Notes due 2016 (the “2016 SPLNG Senior Notes”) and $0.4 billion of 6.50% Senior Secured Notes due 2020 (the “2020 SPLNG Senior Notes” and collectively with the 2016 SPLNG Senior Notes, the “SPLNG Senior Notes”). Under the indentures governing the SPLNG Senior Notes (the “SPLNG Indentures”), except for permitted tax distributions, SPLNG may not make distributions until certain conditions are satisfied, including: (1) there must be on deposit in an interest payment account an amount equal to one-sixth of the semi-annual interest payment multiplied by the number of elapsed months since the last semi-annual interest payment, and (2) there must be on deposit in a permanent debt service reserve fund an amount equal to one semi-annual interest payment. Distributions are permitted only after satisfying the foregoing funding requirements, a fixed charge coverage ratio test of 2:1 and other conditions specified in the SPLNG Indentures.

As of December 31, 2015 and 2014, we classified $77.4 million and $15.0 million, respectively, as current restricted cash for the payment of current interest due. As of December 31, 2015 and 2014, we classified the permanent debt service reserve fund of $13.7 million and $76.1 million, respectively, as non-current restricted cash. These cash accounts are controlled by a collateral trustee; therefore, these amounts are shown as restricted cash on our Consolidated Balance Sheets.

SPL Reserve

During 2013, SPL entered into four credit facilities aggregating $5.9 billion (collectively, the “2013 SPL Credit Facilities”). In June 2015, SPL entered into four credit facilities aggregating $4.6 billion (collectively, the “2015 SPL Credit Facilities”), which replaced the 2013 SPL Credit Facilities. Under the terms and conditions of the 2015 SPL Credit Facilities (and previously the 2013 SPL Credit Facilities), SPL is required to deposit all cash received into reserve accounts controlled by a collateral trustee. The usage or withdrawal of such cash is restricted to the payment of liabilities related to the Liquefaction Project; therefore, these amounts are shown as restricted cash on our Consolidated Balance Sheets.

During 2013, SPL issued an aggregate principal amount of $2.0 billion, before premium, of 5.625% Senior Secured Notes due 2021 (the “2021 SPL Senior Notes”), $1.0 billion of 6.25% Senior Secured Notes due 2022 (the “2022 SPL Senior Notes”) and $1.0 billion of 5.625% Senior Secured Notes due 2023 (the “Initial 2023 SPL Senior Notes”). During 2014, SPL issued an aggregate principal amount of $2.0 billion of 5.75% Senior Secured Notes due 2024 (the “2024 SPL Senior Notes”) and additional 5.625% Senior Secured Notes due 2023 in an aggregate principal amount of $0.5 billion, before premium (collectively with the Initial 2023 SPL Senior Notes, the “2023 SPL Senior Notes”). In March 2015, SPL issued an aggregate principal amount of $2.0 billion of 5.625% Senior Secured Notes due 2025 (the “2025 SPL Senior Notes” and collectively with the 2021 SPL Senior Notes, the 2022 SPL Senior Notes, the 2023 SPL Senior Notes and the 2024 SPL Senior Notes, the “SPL Senior Notes”). The use of cash proceeds from the SPL Senior Notes is restricted to the payment of liabilities related to the Liquefaction Project; therefore, these amounts are shown as restricted cash on our Consolidated Balance Sheets. See Note 10—Debt for additional details about our debt.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

As of December 31, 2015 and 2014, we classified $189.3 million and $155.8 million, respectively, as current restricted cash held by SPL for the payment of current liabilities, including interest payments, related to the Liquefaction Project and zero and $457.1 million, respectively, as non-current restricted cash held by SPL for future Liquefaction Project construction costs.

CTPL Reserve

In May 2013, CTPL entered into a $400.0 million term loan facility (the "CTPL Term Loan"). As of December 31, 2015 and 2014, we classified $7.9 million and $24.9 million, respectively, as current restricted cash held by CTPL for the payment of current liabilities and zero and $11.3 million, respectively, as non-current restricted cash held by CTPL because the usage and withdrawal of such funds is primarily restricted to the payment of liabilities related to modifications of the Creole Trail Pipeline in order to enable bi-directional natural gas flow, and for the payment of interest during construction of such modifications. The restricted cash reserved to pay interest during construction is controlled by a collateral agent and can only be released by the collateral agent upon satisfaction of certain terms and conditions. CTPL is required to pay annual fees to the administrative and collateral agents.

NOTE 5—INVENTORY

As of December 31, 2015 and 2014, inventory consisted of the following (in thousands):

	December 31,	
	2015	2014
Natural gas	$5,724	$—
LNG	3,690	4,293
Materials and other	7,253	3,493
Total inventory	$16,667	$7,786

NOTE 6—PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consists of LNG terminal costs and fixed assets, as follows (in thousands):

	December 31,	
	2015	2014
LNG terminal costs		
LNG terminal	$2,478,036	$2,240,233
LNG terminal construction-in-process	9,859,836	7,082,732
LNG site and related costs, net	135	141
Accumulated depreciation	(411,907)	(348,907)
Total LNG terminal costs, net	11,926,100	8,974,199
Fixed assets		
Computer and office equipment	1,126	1,105
Furniture and fixtures	1,375	1,375
Computer software	4,238	2,411
Vehicles	2,081	1,507
Machinery and equipment	1,906	1,508
Other	93	94
Accumulated depreciation	(5,317)	(3,843)
Total fixed assets, net	5,502	4,157

Property, plant and equipment, net	$11,931,602	$8,978,356

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CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

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 with similar estimated useful lives have a depreciable range between 15 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
Regasification processing equipment (recondensers, vaporization and vents)	30
Sendout pumps	20
Other	15-30

Fixed Assets

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 7—DERIVATIVE INSTRUMENTS

We have entered into the following derivative instruments that are reported at fair value:

- commodity derivatives to hedge the exposure to price risk attributable to future: (1) sales of our LNG inventory and (2) purchases of natural gas to operate the Sabine Pass LNG terminal ("Natural Gas Derivatives");
- commodity derivatives consisting of natural gas purchase agreements and associated economic hedges to secure natural gas feedstock for the Liquefaction Project ("Liquefaction Supply Derivatives"); and
- interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2015 SPL Credit Facilities (and previously the 2013 SPL Credit Facilities) ("Interest Rate Derivatives").

None of our derivative instruments are designated as cash flow hedging instruments, and changes in fair value are recorded within our Consolidated Statements of Operations.

SPLNG has elected to account for a portion of the Natural Gas Derivatives as normal purchase normal sale transactions, exempt from fair value accounting. Gains and losses for these physical hedges are not reflected on our Consolidated Statements of Operations until the period of delivery. SPLNG had not posted collateral for such forward contracts as of December 31, 2015 and 2014.

The following table shows the fair value (in thousands) of the derivative instruments that are required to be measured at fair value on a recurring basis as of December 31, 2015 and 2014, which are classified as other current assets, non-current derivative assets, derivative liabilities or other non-current liabilities in our Consolidated Balance Sheets.

	Fair Value Measurements as of							
	December 31, 2015				December 31, 2014			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total

					(Level 1)			
Natural Gas Derivatives asset	$—	$ 39	$ —	$39	$—	$ 1,216	$ —	$1,216
Liquefaction Supply Derivatives asset (liability)	—	(25)	32,492	32,467	—	—	342	342
Interest Rate Derivatives liability	—	(8,740)	—	(8,740)	—	(12,036)	—	(12,036)

The estimated fair values of our Natural Gas Derivatives are the amounts at which the instruments could be exchanged currently between willing parties. We value these derivatives using observable commodity price curves and other relevant data.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

We value the Interest Rate Derivatives using valuations based on the initial trade prices. Using an income-based approach, subsequent valuations are based on observable inputs to the valuation model including interest rate curves, risk adjusted discount rates, credit spreads and other relevant data.

The fair value of substantially all of the Liquefaction Supply Derivatives is developed through the use of internal models which are impacted by inputs that are unobservable in the marketplace. As a result, the fair value of the Liquefaction Supply Derivatives is designated as Level 3 within the valuation hierarchy. The curves used to generate the fair value of the Liquefaction Supply Derivatives are based on basis adjustments applied to forward curves for a liquid trading point. In addition, there may be observable liquid market basis information in the near term, but terms of a particular Liquefaction Supply Derivatives contract may exceed the period for which such information is available, resulting in a Level 3 classification. In these instances, the fair value of the contract incorporates extrapolation assumptions made in the determination of the market basis price for future delivery periods in which applicable commodity basis prices were either not observable or lacked corroborative market data. Internal fair value models that include contractual pricing with a fixed basis include fixed basis amounts for delivery at locations for which no market currently exists. Internal fair value models also include conditions precedent to the respective long-term natural gas purchase agreements. As of December 31, 2015 and 2014, some of the Liquefaction Supply Derivatives existed within markets for which the pipeline infrastructure has not been developed to accommodate marketable physical gas flow. In the absence of infrastructure to accommodate marketable physical gas flow, our internal fair value models are based on a market price that equates to our own contractual pricing due to: (1) the inactive and unobservable market and (2) conditions precedent and their impact on the uncertainty in the timing of our actual receipt of the physical volumes associated with each forward. The fair value of the Liquefaction Supply Derivatives is predominantly driven by market commodity basis prices and our assessment of the associated conditions precedent, including evaluating whether the respective market is available as pipeline infrastructure is developed. Upon the completion and placement into service of relevant pipeline infrastructure to accommodate marketable physical gas flow, we recognize a gain or loss based on the fair value of the respective natural gas purchase agreements as of the reporting date.

There were no transfers into or out of Level 3 Liquefaction Supply Derivatives for the years ended December 31, 2015, 2014 and 2013. As all of the Liquefaction Supply Derivatives are either purely index-priced or index-priced with a fixed basis, we do not believe that a significant change in market commodity prices would have a material impact on our Level 3 fair value measurements. The following table includes quantitative information for the unobservable inputs for the Level 3 Liquefaction Supply Derivatives as of December 31, 2015:

	Net Fair Value Asset (in thousands)	Valuation Technique	Significant Unobservable Input	Significant Unobservable Inputs Range
Liquefaction Supply Derivatives	$32,492	Income Approach	Basis Spread	$ (0.350) - $0.050

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 net settlement. The use of derivative instruments exposes us to counterparty credit risk that a counterparty will be unable to meet its commitments in instances when our derivative instruments are in an asset position.

Commodity Derivatives

We recognize all commodity derivative instruments that qualify for derivative accounting treatment, including the Natural Gas Derivatives and the Liquefaction Supply Derivatives (collectively, “Commodity Derivatives”), as either assets or liabilities and measure those instruments at fair value. Changes in the fair value of our Commodity Derivatives are reported in earnings.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

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

	December 31, 2015			December 31, 2014		
	Natural Gas Derivatives (1)	Liquefaction Supply Derivatives	Total	Natural Gas Derivatives (1)	Liquefaction Supply Derivatives	Total
Balance Sheet Location						
Other current assets	$39	$2,737	$2,776	$1,216	$76	$1,292
Non-current derivative assets	—	30,304	30,304	—	586	586
Total derivative assets	39	33,041	33,080	1,216	662	1,878
Derivative liabilities	—	(490)	(490)	—	(53)	(53)
Other non-current liabilities	—	(84)	(84)	—	(267)	(267)
Total derivative liabilities	—	(574)	(574)	—	(320)	(320)
Derivative asset, net	$39	$32,467	$32,506	$1,216	$342	$1,558

(1) Does not include a collateral deposit of $0.4 million and a collateral call of $1.1 million for such contracts, which are included in other current assets in our Consolidated Balance Sheets as of December 31, 2015 and 2014, respectively.

The following table (in thousands) shows the changes in the fair value and settlements and location of our Commodity Derivatives recorded on our Consolidated Statements of Operations during the years ended December 31, 2015, 2014 and 2013:

		Year Ended December 31,		
	Statement of Operations Location	2015	2014	2013
Natural Gas Derivatives loss	Revenues	$—	$(31)	$(463)
Natural Gas Derivatives gain	Operating and maintenance expense	2,065	1,389	657
Liquefaction Supply Derivatives gain (1)	Operating and maintenance expense	32,503	342	—

(1) Does not include the realized value associated with derivative instruments that settle through physical delivery.

The use of Commodity Derivatives exposes us to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments in instances when our Commodity Derivatives are in an asset position.

Natural Gas Derivatives

Our Natural Gas Derivatives 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. We are required by these financial institutions to use margin deposits as credit support for our Natural Gas Derivatives activities.

Liquefaction Supply Derivatives

SPL has entered into index-based physical natural gas supply contracts and associated economic hedges to secure natural gas feedstock for the Liquefaction Project. The terms of the physical contracts primarily range from approximately one to seven years and commence upon the occurrence of conditions precedent, including the date of first commercial operation of specified Trains of the Liquefaction Project. We recognize the Liquefaction Supply Derivatives as either assets or liabilities and measure those instruments at fair value. Changes in the fair value of the Liquefaction Supply Derivatives are reported in earnings. As of December 31, 2015, SPL has secured up to approximately 2,154.2 million MMBtu of natural gas feedstock through natural gas purchase agreements. The notional natural gas position of the Liquefaction Supply Derivatives was approximately 1,240.5 million MMBtu.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Interest Rate Derivatives

SPL has entered into Interest Rate Derivatives to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the 2015 SPL Credit Facilities. The Interest Rate Derivatives hedge a portion of the expected outstanding borrowings over the term of the 2015 SPL Credit Facilities.

In March 2015, SPL settled a portion of its Interest Rate Derivatives and we recognized a derivative loss of $34.7 million within our Consolidated Statements of Operations in conjunction with the termination of approximately $1.8 billion of commitments under the 2013 SPL Credit Facilities as discussed in Note 10—Debt. In May 2014, SPL settled a portion of its Interest Rate Derivatives and recognized a derivative loss of $9.3 million within our Consolidated Statements of Operations in conjunction with the early termination of approximately $2.1 billion of commitments under the 2013 SPL Credit Facilities.

At December 31, 2015, SPL had the following Interest Rate Derivatives outstanding:

	Initial Notional Amount	Maximum Notional Amount	Effective Date	Maturity Date	Weighted Average Fixed Interest Rate Paid	Variable Interest Rate Received
Interest Rate Derivatives	$20.0 million	$628.8 million	August 14, 2012	July 31, 2019	1.98%	One-month LIBOR

The following table (in thousands) shows the fair value and location of our Interest Rate Derivatives on our Consolidated Balance Sheets:

	Balance Sheet Location	Fair Value Measurements as of December 31, 2015	December 31, 2014
Interest Rate Derivatives	Derivative liabilities	$(5,940)	$(23,194)
Interest Rate Derivatives	Non-current derivative assets (Other non-current liabilities)	(2,800)	11,158

The following table (in thousands) details the effect of our Interest Rate Derivatives included in Other Comprehensive Income ("OCI") and accumulated other comprehensive income ("AOCI") during the year ended December 31, 2013. The Interest Rate Derivatives had no effect on OCI during the years ended December 31, 2015 and 2014.

	Gain (Loss) in OCI	Gain (Loss) Reclassified from AOCI into Interest Expense (Effective Portion)	Losses Reclassified into Earnings as a Result of Discontinuance of Cash Flow Hedge Accounting
Year Ended December 31, 2013			
Interest Rate Derivatives - Designated	$21,297	$—	$5,807
Interest Rate Derivatives - Settlements	(30)	—	166

The following table (in thousands) 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 Operations during the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
Interest Rate Derivatives gain (loss)	$(41,722)	$(119,401)	$88,596

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Balance Sheet Presentation

Our Commodity Derivatives and Interest Rate Derivatives are presented on a net basis on our Consolidated Balance Sheets as described above. The following table shows the fair value (in thousands) of our derivatives outstanding on a gross and net basis:

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, 2015			
Natural Gas Derivatives	$188	$(149)	$39
Liquefaction Supply Derivatives	33,636	(595)	33,041
Liquefaction Supply Derivatives	(574)	—	(574)
Interest Rate Derivatives	(8,740)	—	(8,740)
As of December 31, 2014			
Natural Gas Derivatives	1,226	(10)	1,216
Liquefaction Supply Derivatives	662	—	662
Liquefaction Supply Derivatives	(320)	—	(320)
Interest Rate Derivatives	11,158	—	11,158
Interest Rate Derivatives	(23,194)	—	(23,194)

NOTE 8—OTHER NON-CURRENT ASSETS

As of December 31, 2015 and 2014, other non-current assets consisted of the following (in thousands):

	December 31,	
	2015	2014
Advances made under EPC and non-EPC contracts	$32,049	$6,414
Advances made to municipalities for water system enhancements	89,953	36,441
Tax-related payments and receivables	27,615	24,093
Conveyed assets to non-affiliates	—	14,751
Other	50,396	42,822
Total other non-current assets	$200,013	$124,521

NOTE 9—ACCRUED LIABILITIES

As of December 31, 2015 and 2014, accrued liabilities consisted of the following (in thousands):

	December 31,	
	2015	2014
Interest expense and related debt fees	$150,336	$112,858
Liquefaction Project costs	66,223	22,014
LNG terminal costs	3,918	1,077
Other accrued liabilities	3,815	629
Total accrued liabilities	$224,292	$136,578

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

NOTE 10—DEBT

As of December 31, 2015 and 2014, our debt consisted of the following (in thousands):

	Interest Rate	December 31, 2015	December 31, 2014
Long-term debt			
2016 SPLNG Senior Notes	7.500%	$—	$1,665,500
2020 SPLNG Senior Notes	6.500%	420,000	420,000
2021 SPL Senior Notes	5.625%	2,000,000	2,000,000
2022 SPL Senior Notes	6.250%	1,000,000	1,000,000
2023 SPL Senior Notes	5.625%	1,500,000	1,500,000
2024 SPL Senior Notes	5.750%	2,000,000	2,000,000
2025 SPL Senior Notes	5.625%	2,000,000	—
2015 SPL Credit Facilities (1)	(2)	845,000	—
CTPL Term Loan (3)	(4)	400,000	400,000
Total long-term debt		10,165,000	8,985,500
Long-term debt premium (discount)			
2016 SPLNG Senior Notes		—	(8,998)
2021 SPL Senior Notes		8,718	10,177
2023 SPL Senior Notes		6,392	7,089
CTPL Term Loan		(1,429)	(2,435)
Total long-term debt, net		10,178,681	8,991,333
Current debt			
2016 SPLNG Senior Notes		1,665,500	—
2016 SPLNG Senior Notes - discount		(4,303)	—
SPL Working Capital Facility (5)	(6)	15,000	—
Total current debt, net		1,676,197	—
Total debt, net		$11,854,878	$8,991,333

(1) Matures on the earlier of December 31, 2020 or the second anniversary of the completion date of Trains 1 through 5 of the Liquefaction Project.

(2) Variable interest rate, at SPL’s election, is LIBOR or the base rate plus the applicable margin. The applicable margins for LIBOR loans range from 1.30% to 1.75%, depending on the applicable 2015 SPL Credit Facility, and the applicable margin for base rate loans is 1.75%. Interest on LIBOR loans is due and payable at the end of each LIBOR period, and interest on base rate loans is due and payable at the end of each quarter.

(3) Matures on May 28, 2017, when the full amount of the outstanding principal obligations must be repaid.

(4) Variable interest rate, at CTPL’s election, is LIBOR or the base rate plus the applicable margin. CTPL has historically elected LIBOR loans, for which the applicable margin is 3.25% and is due and payable at the end of each LIBOR period.

(5) Matures on December 31, 2020, with various terms for underlying loans, as further described below under SPL Working Capital Facility. As of December 31, 2014, no loans were outstanding under the $325.0 million senior letter of credit and reimbursement agreement that was entered into in April 2014 (the “SPL LC Agreement”) it replaced.

(6)

Variable interest rates, based on LIBOR or the base rate, as further described below under SPL Working Capital Facility.

For the years ended December 31, 2015, 2014 and 2013, we incurred $707.7 million, $580.2 million and $414.0 million of total interest cost, respectively, of which we capitalized and deferred $523.1 million, $403.2 million and $233.0 million, respectively, of interest cost, including amortization of debt issuance costs, primarily related to the construction of the first four Trains of the Liquefaction Project.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Below is a schedule of future principal payments that we are obligated to make on our outstanding debt at December 31, 2015 (in thousands):

Years Ending December 31,	Principal Payments
2016	$1,680,500
2017	400,000
2018	—
2019	—
2020	1,265,000
Thereafter	8,500,000
Total	$11,845,500

SPLNG Senior Notes

The terms of the 2016 SPLNG Senior Notes and the 2020 SPLNG Senior Notes are substantially similar. Interest on the SPLNG Senior Notes is payable semi-annually in arrears. Subject to permitted liens, the SPLNG Senior Notes are secured on a first-priority basis by a security interest in all of SPLNG's equity interests and substantially all of its operating assets.

SPLNG may redeem all or part of the 2016 SPLNG Senior Notes at any time, and from time to time, at a redemption price equal to 100% of the principal plus any accrued and unpaid interest plus the greater of:

- 1.0% of the principal amount of the 2016 SPLNG Senior Notes; or
- the excess of: (1) the present value at such redemption date of (a) the redemption price of the 2016 SPLNG Senior Notes plus (b) all required interest payments due on the 2016 SPLNG Senior Notes (excluding accrued but unpaid interest to the redemption date), computed using a discount rate equal to the treasury rate as of such redemption date plus 50 basis points; over (2) the principal amount of the 2016 SPLNG Senior Notes, if greater.

SPLNG may redeem all or part of the 2020 SPLNG Senior Notes at any time on or after November 1, 2016, at fixed redemption prices specified in the indenture governing the 2020 SPLNG Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. SPLNG may also, at its option, redeem all or part of the 2020 SPLNG Senior Notes at any time prior to November 1, 2016, at a "make-whole" price set forth in the indenture governing the 2020 SPLNG Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption.

Under the SPLNG Indentures, except for permitted tax distributions, SPLNG may not make distributions until certain conditions are satisfied as described in Note 4—Restricted Cash. During the years ended December 31, 2015, 2014 and 2013, SPLNG made distributions of $337.3 million, $346.9 million and $348.9 million, respectively, after satisfying all the applicable conditions in the SPLNG Indentures.

SPL Senior Notes

The terms of the SPL Senior Notes are governed by a common indenture (the "SPL Indenture"), and interest on the SPL Senior Notes is payable semi-annually in arrears. The SPL Indenture contains 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; issue preferred stock, make certain investments or pay dividends or distributions on capital stock or subordinated indebtedness; 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; 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, substantial completion of Trains 1 and 2 has occurred, deposits are made into debt service reserve accounts as required and a debt service coverage ratio for the prior 12-month period and a projected debt service coverage ratio for the upcoming 12-month period of 1.25:1.00 are satisfied.

At any time prior to three months before the respective dates of maturity for each series of the SPL Senior Notes, SPL may redeem all or part of such series of the SPL Senior Notes at a redemption price equal to the "make-whole" price set forth in the SPL Indenture, 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, 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.

2015 SPL Credit Facilities

In June 2015, SPL entered into the 2015 SPL Credit Facilities with commitments aggregating $4.6 billion. The 2015 SPL Credit Facilities are being used to fund a portion of the costs of developing, constructing and placing into operation Trains 1 through 5 of the Liquefaction Project. Borrowings under the 2015 SPL Credit Facilities may be refinanced, in whole or in part, at any time without premium or penalty; however, interest rate hedging and interest rate breakage costs may be incurred. As of December 31, 2015, SPL had $3.8 billion of available commitments and outstanding borrowings of $845.0 million under the 2015 SPL Credit Facilities.

SPL incurred $88.3 million of debt issuance costs in connection with the 2015 SPL Credit Facilities. In addition to interest, SPL is required to pay insurance/guarantee premiums of 0.45% per annum on any drawn amounts under the covered tranches of the 2015 SPL Credit Facilities. The 2015 SPL Credit Facilities also require SPL to pay a quarterly commitment fee calculated at a rate per annum equal to either: (1) 40% of the applicable margin, multiplied by the average daily amount of the undrawn commitment, or (2) 0.70% of the undrawn commitment, depending on the applicable 2015 SPL Credit Facility. The principal of the loans made under the 2015 SPL Credit Facilities must be repaid in quarterly installments, commencing with the earlier of June 30, 2020 and the last day of the first full calendar quarter after the completion date of Trains 1 through 5 of the Liquefaction Project. Scheduled repayments are based upon an 18-year amortization profile, with the remaining balance due upon the maturity of the 2015 SPL Credit Facilities.

The 2015 SPL Credit Facilities contain conditions precedent for borrowings, as well as customary affirmative and negative covenants. The obligations of SPL under the 2015 SPL Credit Facilities 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 and the $1.2 billion Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement (the "SPL Working Capital Facility") described below.

Under the terms of the 2015 SPL Credit Facilities, SPL is required to hedge not less than 65% of the variable interest rate exposure of its projected outstanding borrowings, calculated on a weighted average basis in comparison to its anticipated draw of principal. Additionally, SPL may not make any distributions until substantial completion of Trains 1 and 2 of the Liquefaction Project has occurred, deposits are made into debt service reserve accounts and a debt service coverage ratio test of 1.25:1.00 is satisfied.

2013 SPL Credit Facilities

In May 2013, SPL entered into the 2013 SPL Credit Facilities to fund a portion of the costs of developing, constructing and placing into operation Trains 1 through 4 of the Liquefaction Project, which amended and restated the credit facility that was entered into in 2012 (the "2012 SPL Credit Facility"). As of December 31, 2014, SPL had no outstanding borrowings under the 2013 SPL Credit Facilities. In June 2015, the 2013 SPL Credit Facilities were replaced with the 2015 SPL Credit Facilities.

In March 2015, in conjunction with SPL's issuance of the 2025 SPL Senior Notes, SPL terminated approximately $1.8 billion of commitments under the 2013 SPL Credit Facilities. This termination and the replacement of the 2013 SPL Credit Facilities with the 2015 SPL Credit Facilities in June 2015 resulted in a write-off of debt issuance costs and deferred commitment fees associated with the 2013 SPL Credit Facilities of $96.3 million for the year ended

December 31, 2015. The amendment and restatement of the 2012 SPL Credit Facility with the 2013 SPL Credit Facilities in May 2013 resulted in a write-off of debt issuance costs and deferred commitment fees associated with the 2012 SPL Credit Facility of $88.3 million during the year ended December 31, 2013.

CTPL Term Loan

In May 2013, CTPL entered into the CTPL Term Loan, which was used to fund modifications to the Creole Trail Pipeline and for general business purposes. CTPL incurred $10.0 million of direct lender fees that were recorded as a debt discount. As of December 31, 2015, CTPL had borrowed the full amount of $400.0 million available under the CTPL Term Loan. The outstanding balance may be repaid, in whole or in part, at any time without premium or penalty.

The CTPL Term Loan contains customary affirmative and negative covenants. The obligations of CTPL under the CTPL Term Loan are secured by a first priority lien on substantially all of the personal property of CTPL and all of the general partner and limited partner interests in CTPL.

Cheniere Partners has guaranteed (1) the obligations of CTPL under the CTPL Term Loan if the maturity of the CTPL loans is accelerated following the termination by SPL of a transportation precedent agreement in limited circumstances and (2) the obligations of Cheniere Investments in connection with its obligations under an equity contribution agreement (a) to pay operating expenses of CTPL until CTPL receives revenues under a service agreement with SPL and (b) to fund interest payments on the CTPL loans after the funds in an interest reserve account have been exhausted.

SPL Working Capital Facility

In September 2015, SPL entered into the $1.2 billion SPL Working Capital Facility, which replaced the $325.0 million SPL LC Agreement. 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 (“Letters of Credit”), 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, upon the completion of the debt financing of Train 6 of the Liquefaction Project, request an incremental increase in commitments of up to an additional $390 million. As of December 31, 2015, SPL had $1.1 billion of available commitments, $135.2 million aggregate amount of issued Letters of Credit, $15.0 million in Working Capital Loans and no Swing Line Loans or loans deemed made in connection with a draw upon a Letter of Credit (“LC Loans” and collectively with Working Capital Loans and Swing Line Loans, the “SPL Working Capital Facility Loans”) outstanding under the SPL Working Capital Facility. As of December 31, 2014, SPL had issued letters of credit in an aggregate amount of $9.5 million, and no draws had been made upon any letters of credit issued under the SPL LC Agreement.

SPL Working Capital Facility Loans 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 SPL Working Capital Facility Loans is 1.75% per annum, and the applicable margin for base rate SPL Working Capital Facility Loans is 0.75% per annum. Interest on Swing Line Loans and LC Loans is due and payable on the date the loan becomes due. Interest on LIBOR Working Capital Loans is due and payable at the end of each applicable LIBOR period, and interest on base rate Working Capital Loans is due and payable at the end of each fiscal quarter. However, if such base rate Working Capital Loan is converted into a LIBOR Working Capital 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 incurred $27.5 million of debt issuance costs in connection with the SPL Working Capital Facility. 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 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 “LC Draw”) to be deemed an LC Loan, SPL is required to pay the full amount of the LC Draw on or prior to the business day following the notice of the LC Draw. An LC Draw accrues interest at an annual rate of 2.0% plus the base rate. As of December 31, 2015, no 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. LC Loans have a term of up to one year. 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 Swing Line Loan is made and (3) the first borrowing date for a Working Capital Loan or Swing Line Loan occurring at least three business days following the date the 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 and the 2015 SPL Credit Facilities.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Fair Value Disclosures

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

	December 31, 2015		December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
2016 SPLNG Senior Notes, net of discount (1)	$1,661,197	$1,652,891	$1,656,502	$1,718,621
2020 SPLNG Senior Notes (1)	420,000	403,200	420,000	428,400
2021 SPL Senior Notes, net of premium (1)	2,008,718	1,832,955	2,010,177	1,985,050
2022 SPL Senior Notes (1)	1,000,000	912,500	1,000,000	1,020,000
2023 SPL Senior Notes, net of premium (1)	1,506,392	1,299,263	1,507,089	1,476,947
2024 SPL Senior Notes (1)	2,000,000	1,715,000	2,000,000	1,970,000
2025 SPL Senior Notes (1)	2,000,000	1,710,000	—	—
2015 SPL Credit Facilities (2)	845,000	845,000	—	—
CTPL Term Loan, net of discount (2)	398,571	400,000	397,565	400,000
SPL Working Capital Facility (2)	15,000	15,000	—	—

(1) The Level 2 estimated fair value was based on quotations obtained from broker-dealers who make markets in these and similar instruments based on the closing trading prices on December 31, 2015 and 2014, as applicable.

(2) 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 11—RELATED PARTY TRANSACTIONS

LNG Terminal Capacity Agreements

Terminal Use Agreement

SPL obtained approximately 2.0 Bcf/d of regasification capacity 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, continuing until at least 20 years after SPL delivers its first commercial cargo at the Liquefaction Project.

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. During the years ended December 31, 2015, 2014 and 2013, we recorded $18.8 million, $26.1 million and $26.6 million, respectively, as operating and maintenance expense related to this obligation.

Cheniere Investments, SPL and SPLNG entered into the terminal use rights assignment and agreement (the “TURA”) pursuant to which Cheniere Investments has the right to use SPL’s reserved capacity under the TUA and has the obligation to make the monthly capacity payments required by the TUA to SPLNG. However, the revenue earned by SPLNG from the capacity payments made under the TUA and the loss incurred by Cheniere Investments under the TURA are eliminated upon consolidation of our Financial Statements. We have guaranteed the obligations of SPL under its TUA and the obligations of Cheniere Investments under the TURA.

In an effort to utilize Cheniere Investments' reserved capacity under the TURA during construction of the Liquefaction Project, Cheniere Marketing has entered into an amended and restated variable capacity rights agreement with Cheniere Investments (the "Amended and Restated VCRA") pursuant to which Cheniere Marketing is obligated to pay Cheniere Investments 80% of the expected gross margin of each cargo of LNG that Cheniere Marketing arranges for delivery to the Sabine Pass LNG terminal. We recorded no revenues—affiliate from Cheniere Marketing during the years ended December 31, 2015, 2014 and 2013, respectively, related to the Amended and Restated VCRA.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Cheniere Marketing SPA

Cheniere Marketing has entered into an 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.

Commissioning Agreement

In May 2015, SPL entered into an agreement with Cheniere Marketing that obligates Cheniere Marketing in certain circumstances to buy LNG cargoes produced during the periods while Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") has control of, and is commissioning, the first four Trains of the Liquefaction Project.

Pre-commercial LNG Marketing Agreement

In May 2015, SPL entered into an agreement with Cheniere Marketing that authorizes Cheniere Marketing to act on SPL's behalf to market and sell pre-commercial LNG that has not been accepted by BG Gulf Coast LNG, LLC.

Services Agreements

As of December 31, 2015 and 2014, we had $39.8 million and $27.3 million of advances to affiliates, respectively, under the services agreements described below. During the years ended December 31, 2015, 2014 and 2013, we recorded general and administrative expense—affiliate of $122.3 million, $101.4 million and $129.8 million, respectively, and operating and maintenance expense—affiliate of $29.4 million, $21.1 million and $29.3 million, respectively, under the services agreements described below.

Cheniere Partners Services Agreement

We have entered into a services agreement with Cheniere Terminals, a wholly owned subsidiary of Cheniere, pursuant to which Cheniere Terminals is entitled to a quarterly non-accountable overhead reimbursement charge of $2.8 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 entered into 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 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 entered into 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 incurs 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 incurs costs 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.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

SPLNG MSA

SPLNG has entered into 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 incurs a monthly fixed fee of $520,000 (indexed for inflation) under the SPLNG MSA.

SPL O&M Agreement

SPL has entered into 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 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 the Liquefaction Project is operational, the services include all necessary services required to operate and maintain the Liquefaction Project. Before the Liquefaction Project is operational, 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 Liquefaction Project 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 such 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 entered into 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 our behalf and providing contract administration services for all contracts associated with the Liquefaction Project. Under the SPL MSA, 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 entered into 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 the counterparty 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.

CTPL MSA

CTPL has entered into a management services agreement (the “CTPL MSA”) with Cheniere Terminals pursuant to which Cheniere Terminals manages the modification and operation of the Creole Trail Pipeline, excluding those matters provided for under the CTPL O&M Agreement. The services include, among other services, exercising the day-to-day management of CTPL’s affairs and business, managing CTPL’s regulatory matters, managing bank and brokerage accounts and financial books and records of CTPL’s business and operations and providing contract administration services for all contracts associated with the pipeline facilities. Under the CTPL MSA, CTPL pays a monthly fee equal to 3.0% of the capital expenditures to enable bi-directional natural gas flow on the Creole Trail Pipeline incurred in the previous month.

LNG Lease Agreement

In September 2011, Cheniere Investments entered into an agreement in the form of a lease (the “LNG Lease Agreement”) with Cheniere Marketing that enables Cheniere Investments to supply the Sabine Pass LNG terminal with LNG to maintain proper

LNG inventory levels and temperature. The LNG Lease Agreement also enables Cheniere Investments to hedge the exposure to variability in expected future cash flows of the LNG inventory. Under the terms of the LNG Lease Agreement, Cheniere Marketing funds all activities related to the purchase and hedging of the LNG, and Cheniere Investments reimburses Cheniere Marketing for all costs and assumes full price risk associated with these activities.

As a result of Cheniere Investments assuming full price risk associated with the LNG Lease Agreement, any LNG inventory purchased by Cheniere Marketing under this arrangement is classified as inventory—affiliate on our Consolidated Balance Sheets. This amount is recorded at cost and subject to LCM adjustments at the end of each period. Inventory—affiliate cost is determined using the average cost method. Recoveries of losses resulting from interim period LCM adjustments are made due to market price recoveries on the same inventory—affiliate in the same fiscal year and are recognized as gains in later interim periods with such gains not exceeding previously recognized losses. Gains or losses on the sale of inventory—affiliate and LCM adjustments are recorded as revenues on our Consolidated Statements of Operations. As of December 31, 2015 and 2014, we had no LNG inventory—affiliate recorded on our Consolidated Balance Sheets under the LNG Lease Agreement.

Agreement to Fund SPLNG’s Cooperative Endeavor Agreements (“CEAs”)

In July 2007, SPLNG executed CEAs with various Cameron Parish, Louisiana taxing authorities that allow them to collect certain annual property tax payments from SPLNG from 2007 through 2016. This ten-year initiative represents an aggregate commitment of up to $25.0 million, and SPLNG will make resources available to the Cameron Parish taxing authorities on an accelerated basis 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 will grant SPLNG a dollar-for-dollar credit against future ad valorem taxes to be levied against the Sabine Pass LNG terminal starting in 2019. In September 2007, SPLNG entered into an agreement with Cheniere Marketing, pursuant to which Cheniere Marketing would pay SPLNG additional TUA revenues equal to any and all amounts payable under the CEAs in exchange for a similar amount of credits against future TUA payments it would owe SPLNG under its TUA starting in 2019. In June 2010, Cheniere Marketing assigned its TUA to Cheniere Investments and concurrently entered into a variable capacity rights agreement, allowing Cheniere Marketing to utilize Cheniere Investments’ capacity under the TUA after the assignment. In July 2012, Cheniere Investments entered into the Amended and Restated VCRA with Cheniere Marketing in order for Cheniere Investments to utilize during construction of the Liquefaction Project the capacity rights granted under the TURA. Cheniere Marketing will continue to fund the CEAs during the term of the Amended and Restated VCRA and, in exchange, Cheniere Marketing will receive the benefit of any future credits.

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 a long-term obligation. As of December 31, 2015 and 2014, we had $22.1 million and $19.6 million, respectively, of both other non-current assets resulting from SPLNG’s ad valorem tax payments and non-current liabilities—affiliate resulting from these payments received from Cheniere Marketing.

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. As a result, SPLNG records the purchases of natural gas and LNG from Cheniere Marketing to be utilized as fuel to operate the Sabine Pass LNG terminal as operating and maintenance expense.

SPLNG recorded operating and maintenance expense of $5.0 million, $3.3 million and $3.3 million in the years ended December 31, 2015, 2014 and 2013, respectively, for natural gas purchased from Cheniere Marketing under these agreements. SPLNG recorded revenues—affiliate of $11.7 million, $0.7 million and $14.7 million in the years ended December 31, 2015, 2014 and 2013, respectively, for natural gas sold to Cheniere Marketing under these agreements.

Tug Boat Lease Sharing Agreement

In connection with its tug boat lease, Sabine Pass Tug Services, LLC ("Tug Services"), a wholly owned subsidiary of SPLNG, entered into a tug sharing agreement with a wholly owned subsidiary of Cheniere to provide its LNG cargo vessels with tug boat and marine services at the Sabine Pass LNG terminal. Tug Services recorded revenues—affiliate of $2.8 million pursuant to this agreement in each of the years ended December 31, 2015, 2014 and 2013.

LNG Terminal Export Agreement

In January 2010, SPLNG and Cheniere Marketing entered into 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, 2015, 2014 and 2013.

State Tax Sharing Agreements

In November 2006, SPLNG entered into 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 computed 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.

In August 2012, SPL entered into 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.

In May 2013, CTPL entered into 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 12—LEASES

During the years ended December 31, 2015, 2014 and 2013, we recognized rental expense for all operating leases of $10.5 million, $10.5 million and $10.0 million, respectively, related primarily to office space and land sites. Our land site leases for the Sabine Pass LNG terminal have initial terms varying up to 30 years with multiple options to renew up to an additional 60 years.

Future annual minimum lease payments, excluding inflationary adjustments, are as follows (in thousands):

Years Ending December 31,	Operating Leases
2016	$2,620
2017	2,220

2018	2,219
2019	2,197
2020	2,056
Thereafter (1)	29,664
Total	$40,976

(1) Includes certain lease option renewals that are reasonably assured.

NOTE 13—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, 2015, are not recognized as liabilities but require disclosures in our Consolidated Financial Statements.

LNG Terminal Commitments and Contingencies

Obligations under LNG TUAs

SPLNG has entered into third-party TUAs with Total Gas & Power North America, Inc. 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 Bechtel EPC Contracts

SPL has entered into lump sum turnkey contracts with Bechtel for the engineering, procurement and construction of Trains 1 and 2 (the “EPC Contract (Trains 1 and 2)”), Trains 3 and 4 (the “EPC Contract (Trains 3 and 4)”) and Train 5 (the “EPC Contract (Train 5)”) of the Liquefaction Project.

The EPC Contract (Trains 1 and 2), the EPC Contract (Trains 3 and 4) and the EPC Contract (Train 5) provide that SPL will pay Bechtel contract prices of $4.1 billion, $3.8 billion and $3.0 billion, respectively, subject to adjustment by change order. SPL has the right to terminate each 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 $30.0 million depending on the termination date.

Obligations under SPAs

SPL has entered into third-party SPAs which obligate SPL to purchase and liquefy sufficient quantities of natural gas to deliver 1,030.0 million MMBtu per year of LNG to the customers’ vessels, subject to completion of construction of Trains 1 through 5 of the Liquefaction Project.

Obligations under Natural Gas Supply, Transportation and Storage Service Agreements

SPL has entered into index-based physical natural gas supply contracts to secure natural gas feedstock for the Liquefaction Project. The terms of these contracts primarily range from approximately one to seven years and commence upon the occurrence of conditions precedent, including SPL’s declaration to the respective natural gas supplier that it is ready to commence the term of the supply arrangement in anticipation of the date of first commercial operation of the applicable, specified Trains of the Liquefaction Project. As of December 31, 2015, SPL has secured up to approximately 2,154.2 million MMBtu of natural gas feedstock through natural gas purchase agreements, of which we determined that we have purchase obligations for the contracts for which conditions precedent were met.

Additionally, SPL has entered into transportation and storage service agreements for the Liquefaction Project. The initial term of the transportation agreements ranges from 10 to 20 years, with renewal options for certain contracts, and commences upon the occurrence of conditions precedent. The term of our storage service agreements is typically three years.

As of December 31, 2015, SPL’s purchase obligations under natural gas supply, transportation and storage service agreements for contracts in which conditions precedent were met were as follows (in thousands):

Years Ending December 31,	Payments Due (1)
2016	$341,039
2017	284,263
2018	231,550
2019	182,470
2020	189,640
Thereafter	259,273
Total	$1,488,235

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

(1) Pricing of natural gas supply contracts are variable based on market commodity basis prices adjusted for basis spread. Amounts included are based on prices and basis spreads as of December 31, 2015.

Services Agreements

We have entered into certain services agreements with affiliates. See Note 11—Related Party Transactions for information regarding such agreements.

Restricted Net Assets

At December 31, 2015, our restricted net assets of consolidated subsidiaries were approximately $618 million.

Other Commitments

State Tax Sharing Agreements

SPLNG, SPL and CTPL have entered into state tax sharing agreements with Cheniere. See Note 11—Related Party Transactions for information regarding such agreements.

Cooperative Endeavor Agreements

SPLNG has executed CEAs with various Cameron Parish, Louisiana taxing authorities. See Note 11—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. Additionally, we have various lease commitments, as disclosed in Note 12—Leases.

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, 2015, there were no pending legal matters that would reasonably be expected to have a material impact on our consolidated operating results, financial position or cash flows.

NOTE 14—SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2015	2014	2013
Cash paid during the year for interest, net of amounts capitalized and deferred	$135,836	$130,578	$120,908
	230,699	124,741	166,252

Balance in property, plant and equipment, net funded with accounts payable and accrued liabilities (including affiliate)			
Non-cash conveyance of assets	13,169	—	—
Class B units issued in connection with Creole Trail Pipeline Business acquisition	—	—	180,000

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

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 22, 2016, we declared a $0.425 distribution per common unit and the related distribution to our general partner was paid on February 12, 2016 to unitholders of record as of February 1, 2016 for the period from October 1, 2015 to December 31, 2015.

The two-class method dictates that net income (loss) for a period be reduced by the amount of available cash that will be distributed with respect to that period and that any residual amount representing undistributed net income be allocated to common unitholders and other participating unitholders to the extent that each unit may share in net income as if all of the net income for the period had been distributed in accordance with the partnership agreement. Undistributed income is allocated to participating securities based on the distribution waterfall for available cash specified in the partnership agreement. Undistributed losses (including those resulting from distributions in excess of net income) are allocated to common units and other participating securities on a pro rata basis based on provisions of the partnership agreement. Historical income (loss) attributable to a company that was purchased from an entity under common control is allocated to the predecessor owner in accordance with the terms 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 were issued at a discount to the market price of the common units into which they are convertible. This discount totaling $2,130.0 million represents a beneficial conversion feature and is 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 Statements of Partners' Equity. The beneficial conversion feature is considered a dividend that will be distributed ratably with respect to any Class B unit from its issuance date through its conversion date, resulting in an increase in Class B unitholders' equity and a decrease in common and subordinated unitholders' equity. We amortize the beneficial conversion feature assuming a conversion date of June 2017 and August 2017 for Cheniere Holdings' and Blackstone CQP Holdco's Class B units, respectively, although actual conversion may occur prior to or after these assumed dates. We are amortizing using the effective yield method with a weighted average effective yield of 888.7% per year and 966.1% per year for Cheniere Holdings' and Blackstone CQP Holdco's Class B units, respectively. The impact of the beneficial conversion feature is also included in earnings per unit for the years ended December 31, 2015, 2014 and 2013.

The following is a schedule by years, based on the capital structure as of December 31, 2015, of the anticipated impact to the capital accounts in connection with the amortization of the beneficial conversion feature (in thousands):

	Common Units	Class B Units	Subordinated Units
2016	$(29,565)	$99,685	$(70,119)
2017	(594,426)	2,004,209	(1,409,783)

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CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Under our partnership agreement, the incentive distribution rights ("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). We did not allocate earnings or losses to IDR holders for the purpose of the two-class method earnings per unit calculation for any of the periods presented. The following table provides a reconciliation of net loss and the allocation of net loss to the common units, the subordinated units, the general partner and the Creole Trail Pipeline Business for purposes of computing net loss per unit The following table (in thousands, except per unit data) also provides net loss per unit, as adjusted, assuming the common units, subordinated units and the general partner had participated in the pre-acquisition date net losses of the Creole Trail Pipeline Business.

		Limited Partner Units				
	Total	Common Units	Class B Units	Subordinated Units	General Partner	Creole Trail Pipeline Business
Year Ended December 31, 2015						
Net loss	$(318,891)					
Declared distributions	99,018	97,038	—	—	1,980	
Assumed allocation of undistributed net loss	$(417,909)	(121,468)	—	(288,083)	(8,358)	—
Assumed allocation of net loss		$(24,430)	$—	$ (288,083)	$(6,378)	$—
Weighted average units outstanding		57,081	145,333	135,384		
Net loss per unit		$(0.43)	$—	$ (2.13)		
Year Ended December 31, 2014						
Net loss	$(410,036)					
Declared distributions	99,015	97,036	—	—	1,979	
Assumed allocation of undistributed net loss	$(509,051)	(147,952)	—	(350,918)	(10,181)	—
Assumed allocation of net loss		$(50,916)	$—	$ (350,918)	$(8,202)	$—
Weighted average units outstanding		57,079	145,333	135,384		
Net loss per unit		$(0.89)	$—	$ (2.59)		
Year Ended December 31, 2013						
Net loss	$(258,117)					
Declared distributions	99,015	97,035	—	—	1,980	
Assumed allocation of undistributed net loss	$(357,132)	(98,522)	—	(233,680)	(6,780)	(18,150)
Assumed allocation of net loss		$(1,487)	$—	$ (233,680)	$(4,800)	$(18,150)
Assumed allocation of net loss adjusted for the Creole Trail Pipeline Business		$(6,762)	$—	$ (246,192)	$(5,163)	
Weighted average units outstanding		54,235	140,500	135,384		
Net loss per unit		$(0.03)	$—	$ (1.73)		
		$(0.12)	$—	$ (1.82)		

Net loss per unit, adjusted to include pre-acquisition date net losses of the Creole Trail Pipeline Business

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CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

NOTE 16—RECENT ACCOUNTING STANDARDS

The following table provides a brief description of recent accounting standards that had not yet been adopted by the Partnership as of December 31, 2015:

Standard	Description	Expected Date of Adoption	Effect on our Consolidated Financial Statements or Other Significant Matters
ASU 2014-09, Revenue from Contracts with Customers (Topic 606)	The standard amends existing revenue recognition guidance and requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This guidance may be early adopted beginning January 1, 2017, and may be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption.	January 1, 2018	We are currently evaluating the impact of the provisions of this guidance on our Consolidated Financial Statements and related disclosures.
ASU 2014-15, Presentation of Financial Statements-Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern	The standard requires an entity’s management to evaluate, for each reporting period, whether there are conditions and events that raise substantial doubt about the entity’s ability to continue as a going concern within one year after the financial statements are issued. Additional disclosures are required if management concludes that conditions or events raise substantial doubt about the entity’s ability to continue as a going concern. Early adoption is permitted.	December 31, 2016	The adoption of this guidance is not expected to have an impact on our Consolidated Financial Statements or related disclosures.
ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis	This amendment primarily affects asset managers and reporting entities involved with limited partnerships or similar entities, but the analysis is relevant in the evaluation of any reporting organization’s requirement to consolidate a legal entity. This guidance changes (1) the identification of variable interests, (2) the variable interest entity characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. This guidance may be early adopted, and may be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment	January 1, 2016	The adoption of this guidance is not expected to have an impact on our Consolidated Financial Statements or related disclosures.

	as of the date of adoption.		
ASU 2015-03, Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs and ASU 2015-15, Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements	This standard requires debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the debt liability rather than as an asset. Debt issuance costs incurred in connection with line of credit arrangements may be presented as an asset and subsequently amortized ratably over the term of the line of credit arrangement. This guidance may be early adopted, and must be adopted retrospectively to each prior reporting period presented.	January 1, 2016	Upon adoption of this standard, the balance of debt, net will be reduced by the balance of debt issuance costs, net, except for the balance related to line of credit arrangements, on our Consolidated Balance Sheets. Additionally, disclosures will be required for a change in accounting principle.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Standard	Description	Expected Date of Adoption	Effect on our Consolidated Financial Statements or Other Significant Matters
ASU 2015-06, Earnings Per Share (Topic 260): Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions	This standard requires a master limited partnership to allocate net income (losses) of a transferred business entirely to the general partner when computing earnings per unit for periods before the dropdown transaction occurred. This guidance also requires a master limited partnership to disclose the effects of the dropdown transaction on net income (losses) per unit for the periods before and after the dropdown transaction occurred. This guidance may be early adopted, and must be adopted retrospectively to each prior reporting period presented.	January 1, 2016	The adoption of this guidance is not expected to have an impact on our Consolidated Financial Statements or related disclosures.
ASU 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory	This standard requires inventory to be measured at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This guidance may be early adopted and must be adopted prospectively.	January 1, 2017	We are currently evaluating the impact of the provisions of this guidance on our Consolidated Financial Statements and related disclosures.

NOTE 17—SUBSEQUENT EVENTS

In January 2016, we engaged 13 financial institutions to act as Joint Lead Arrangers, Mandated Lead Arrangers and other participants to assist in the structuring and arranging of up to approximately $2.8 billion of senior secured credit facilities. Proceeds from these new credit facilities are intended to be used by us to prepay $400.0 million of the CTPL Term Loan, to redeem or repay $1,665.5 million of the 2016 SPLNG Senior Notes and $420.0 million of the 2020 SPLNG Senior Notes, to pay associated transaction fees, expenses and make-whole amounts, if applicable, and for our general business purposes.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
SUMMARIZED QUARTERLY FINANCIAL DATA
(unaudited)

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2015:				
Revenues	$67,530	$67,689	$67,537	$67,272
Income (loss) from operations	(9,822)	(4,318)	35,921	(18,739)
Net loss	(178,676)	(60,043)	(24,132)	(56,040)
Basic and diluted net income (loss) per common unit (1)	$(0.61)	$(0.01)	$0.18	$0.01
Year ended December 31, 2014:				
Revenues	$67,221	$67,328	$67,590	$66,559
Income (loss) from operations	4,893	(7,791)	(1,862)	5,275
Net loss	(69,733)	(226,224)	(43,240)	(70,839)
Basic and diluted net income (loss) per common unit (1)	$(0.06)	$(0.85)	$0.08	$(0.06)

(1) The sum of the quarterly net income (loss) per common unit may not equal the full year amount as the 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, 2015, 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 55 and is incorporated herein by reference.

ITEM 9B. OTHER INFORMATION

Compliance Disclosure

Pursuant to Section 13(r) of the Exchange Act, if during the fiscal year ended December 31, 2015, we or any of our affiliates had engaged in certain transactions with Iran or with persons or entities designated under certain executive orders, we would be required to disclose information regarding such transactions in our annual report on Form 10-K as required under Section 219 of the Iran Threat Reduction and Syria Human Rights Act of 2012 ("ITRA"). During the fiscal year ended December 31, 2015, we did not engage in any transactions with Iran or with persons or entities related to Iran.

Blackstone CQP Holdco, an affiliate of Blackstone Group, is a holder of more than 29% of our outstanding equity interests and has three representatives on the Board of Directors of Cheniere Partners GP. Accordingly, Blackstone Group may be deemed our "affiliate," as that term is defined in Exchange Act Rule 12b-2. During the year ended December 31, 2015, Blackstone Group has included in its quarterly reports on Form 10-Q for the quarterly periods ended March 31, 2015, June 30, 2015 and September 30, 2015 disclosures pursuant to ITRA regarding two of its portfolio companies that may be deemed to be affiliates of Blackstone Group. Because of the broad definition of "affiliate" in Exchange Act Rule 12b-2, these portfolio companies of Blackstone Group, through Blackstone Group's ownership of Cheniere Partners, may also be deemed to be affiliates of ours. We have not independently verified the disclosure described in the following paragraphs.

Blackstone Group has reported that Hilton Worldwide Holdings Inc. (“Hilton”) has engaged in the following activity during the fiscal quarter ended September 30, 2015: an Iranian governmental delegation stayed at the Transcorp Hilton Abuja for one night. The stays were booked and paid for by the government of Nigeria. The hotel received revenues of approximately $5,320 from these dealings, and net profit to Hilton from these dealings was approximately $495, as reported by Blackstone Group. The gross revenues and net profits attributable to such activities by Hilton during the fiscal year ended December 31, 2015 have not been reported by Hilton. Hilton believes that the hotel stays were exempt from the Iranian Transactions and Sanctions Regulations, 31 C.F.R. Part 560, pursuant to the International Emergency Economic Powers Act (“IEEPA”) and under 31 C.F.R. Section 560.210

(d). Blackstone Group has reported that the Transcorp Hilton Abuja intends to continue engaging in future similar transactions to the extent they remain permissible under applicable laws and regulations.

Blackstone Group has reported that Travelport Worldwide Limited ("Travelport") has engaged in the following activities: as part of its global business in the travel industry, Travelport provides certain passenger travel related Travel Commerce Platform and Technology Services to Iran Air. Travelport also provides certain airline Technology Services to Iran Air Tours. The gross revenues and net profits attributable to such activities by Travelport during the fiscal year ended December 31, 2015 have not been reported by Travelport; the gross revenues and net profits attributable to such activities by Travelport during the first nine months of 2015 were reported by Travelport to be approximately $435,000 and $307,000, respectively. Blackstone Group reported that Travelport intends to continue these business activities with Iran Air and Iran Air Tours as such activities are either exempt from applicable sanctions prohibitions or specifically licensed by the Office of Foreign Assets Control.

In our Form 10-Q reports for the quarterly periods ended on March 31, 2015, June 30, 2015 and September 30, 2015, we disclosed, under "Item 5. Other Information—Compliance Disclosure" in each such report, as amended, activities as required by Section 13(r) of the Exchange Act as transactions or dealings with the government of Iran that have not been specifically authorized by a U.S. federal department or agency. Such disclosures are incorporated herein by reference.

PART III

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

Management of Cheniere Energy Partners, L.P.

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 MKT 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 MKT, respectively.

The audit committee assists the board of directors of our general partner in its oversight of the integrity of our 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/audit-committee/.

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, Lon McCain, Oliver G. Richard, III and James R. Ball, 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 MKT, 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.

Other

We do not have a nominating committee because the directors of our general partner manage our operations. Our general partner is not elected by our unitholders and is not subject to re-election on a regular basis. Unitholders are not entitled to elect the directors of our general partner or to participate directly or indirectly in our management or 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

We have no employees, directors or officers. We are managed by our general partner, Cheniere Partners GP. The following sets forth information, as of February 12, 2016, regarding the individuals who currently serve on the board of directors and as executive officers of our general partner. Neal Shear has served as a director of Cheniere Partners GP since December 13, 2015. Meg Gentle and Lon McCain have served as directors of the general partner since 2007. Keith Teague has served as a director of the general partner since 2008. Messrs. Ball, Klimczak, Pagano and Richard were elected as directors of the general partner in 2012. Philip Meier was elected a director of the general partner in July 2013. Michael Wortley was elected as a director of the general partner in January 2014. John-Paul Munfa was elected as a director of the general partner in 2015. The appointments of Messrs. Klimczak, Meier and Munfa 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	Position with Our General Partner
Neal A. Shear	61	Chairman of the Board and Interim Chief Executive Officer
R. Keith Teague	51	Director, President and Chief Operating Officer
Michael J. Wortley	39	Director, Senior Vice President and Chief Financial Officer
James R. Ball	65	Director
John-Paul Munfa	33	Director
Meg A. Gentle	41	Director
Sean T. Klimczak	39	Director
Lon McCain	67	Director
Philip Meier	56	Director
Vincent Pagano, Jr.	65	Director
Oliver G. Richard, III	63	Director

Neal A. Shear is Chairman of the Board and Interim Chief Executive Officer of our general partner and has held such positions since December 13, 2015. Mr. Shear serves as director, Interim Chief Executive Officer and President of Cheniere. He also serves as Chairman of the Board, Interim Chief Executive Officer and President of Cheniere Holdings. He is also Interim Chief Executive Officer of SPL and Interim Chief Executive Officer and Manager of the general partner of SPLNG. Mr. Shear is currently a partner of Silverpeak Partners LP, a private investment company. Mr. Shear was the Chief Executive Officer of Higgs Capital Management, a commodity focused hedge fund until September 2014. Prior to Higgs Capital Management, Mr. Shear served as Global Head of Securities at UBS Investment Bank from January 2010 to March of 2011. From May 2008 to December 2009, Mr. Shear was a Partner at Apollo Global Management, LLC, where he served as the Head of the Commodities Division. Prior to Apollo Global Management, Mr. Shear spent 26 years at Morgan Stanley serving in various roles including Head of the Commodities Division, Global Head of Fixed Income, Co-Head of Institutional Sales and Trading and Chair of the Commodities Business. He currently serves on the Advisory Board of Green Key Technologies, a financial Voice over Internet Protocol (VoIP) technology company. Mr. Shear received a B.S. from the University of Maryland, Robert H. Smith School of Business Management in 1976 and an M.B.A. from Cornell University, Johnson School of Business in 1978. It was determined that Mr. Shear should serve as a director of our general partner because of his knowledge of and expertise in the energy industry.

R. Keith Teague is President and Chief Operating Officer and a director of our general partner and has held such positions since June 2008. He has served as Executive Vice President-Asset Group of Cheniere since February 2014 and served as Senior Vice President-Asset Group of Cheniere from April 2008 to February 2014. Prior to April 2008, he served as Vice President-Pipeline Operations since May 2006. Mr. Teague has also served as President of CQH Holdings Company, LLC (formerly known as Cheniere Pipeline Company), a wholly owned subsidiary of Cheniere, since January 2005. In addition, Mr. Teague is a director of Cheniere Holdings and President and a manager of SPL. Mr. Teague is also President of the general partner of SPLNG and is responsible for the development, construction and operation of Cheniere’s LNG terminal and pipeline assets. Mr. Teague began his career with Cheniere in February 2004 as Director of Facility Planning. Prior to joining Cheniere, Mr. Teague served as the Director of Strategic Planning for the CMS Panhandle Companies from December 2001 until September 2003. He began his career with Texas Eastern Transmission Corporation where he managed pipeline operations and facility expansion. Mr. Teague received a B.S. in civil engineering from Louisiana Tech University and an M.B.A. from Louisiana State University. With Mr. Teague’s knowledge and expertise relating to the Sabine Pass LNG terminal, it was determined that he should serve as a director of our general partner. Mr. Teague has not held any other directorship positions in the past five years.

Michael J. Wortley is Chief Financial Officer and a director of our general partner and has held such positions since January 2014. Mr. Wortley is also a member of the Executive Committee. Mr. Wortley has been Senior Vice President and Chief Financial Officer of Cheniere since January 2014. Prior to January 2014, he served as Vice President-Strategy and Risk of Cheniere since January 2013. Prior to January 2013, he served as Vice President-Business Development of Cheniere and President of Corpus Christi Liquefaction, LLC, a wholly owned subsidiary of Cheniere, since September 2011. Prior to September 2011, Mr. Wortley served as Cheniere's Vice President-Strategic Planning since January 2009 and Manager-Strategic New Business since August 2007. 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, a publicly traded oil and gas exploration and production company. Mr. Wortley began his career as an Internal Auditor with Union Pacific Resources Corporation, a publicly traded oil and gas exploration and production company subsequently acquired by Anadarko. Mr. Wortley is currently a director and Chief Financial Officer of Cheniere Holdings. Mr. Wortley is also Chief Financial Officer of the general partner of SPLNG and a manager and Chief Financial Officer of SPL. 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. Mr. Wortley has not held any other directorship positions in the past five years.

James R. Ball is a director of our general partner, Chairman of the Executive Committee and a member of the Conflicts Committee. 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. Since 2011, Mr. Ball has served as a senior advisor to Tachebois Limited, an energy and equities advisory firm. 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.

John-Paul Munfa is a director of our general partner and a member of the Executive Committee. Mr. Munfa is a Principal 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.

Meg A. Gentle is a director of our general partner. Ms. Gentle is also a director of Cheniere Holdings. In addition, Ms. Gentle has served as Executive Vice President-Marketing of Cheniere since February 2014 and served as Senior Vice President-Marketing of Cheniere from June 2013 to February 2014. She previously served as Senior Vice President and Chief Financial Officer of Cheniere and our general partner from March 2009 to June 2013 and Senior Vice President of our general partner from June 2008 to March 2009. She served as Senior Vice President - Strategic Planning and Finance for Cheniere from February 2008 to March 2009. Prior to that time, she served as Cheniere's Vice President of Strategic Planning since September 2005 and Manager of Strategic Planning since June 2004. Prior to joining Cheniere, Ms. Gentle spent eight years in energy market development, economic evaluation and long-range planning. She conducted international business development and strategic planning for Anadarko Petroleum Corporation, an oil and natural gas exploration and production company, for six years and energy market analysis for Pace Global Energy Services, an energy management and consulting firm, for two years. Ms. Gentle received her B.A. in economics and international affairs from James Madison University and an M.B.A. from Rice University. It was determined that Ms. Gentle should serve as a director of our general partner because of her experience with strategic planning and finance in the energy industry and because of the perspective she brings as the former Chief Financial Officer of Cheniere, Cheniere Partners GP and the general partner of SPLNG. Ms. Gentle has not held any other directorship positions in the past five years.

Sean T. Klimczak is a director of our general partner and a member of the Executive Committee. In addition, Mr. Klimczak is a director of SPL. Mr. Klimczak is a Senior Managing Director in the Private Equity Group of Blackstone Group, an investment and advisory firm. Prior to joining Blackstone Group in 2005, Mr. Klimczak was an Associate at Madison Dearborn Partners, a private equity investment firm, from 2001 to 2003 and an employee in the Mergers & Acquisitions department of the Investment Banking division of Morgan Stanley, a financial services firm, from 1998 to 2001. Mr. Klimczak received a B.B.A. in finance and business economics from Notre Dame and a Master of Business Administration from Harvard Business School. It was determined that Mr. Klimczak should serve as a director of our general partner because of his significant investment experience with Blackstone Group. Mr. Klimczak has not held any other directorship positions in the past five years.

Lon McCain is a director of our general partner and serves as the Chairman of the Audit Committee and a member of the Conflicts Committee. He 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. During the past five years, he served as a director of Transzap, Inc., a privately held provider of digital data and electronic payment solutions. 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.

Philip Meier is a 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.

Vincent Pagano, Jr. is a director of our general partner and serves as Chairman of the Conflicts Committee and as a member of the Audit Committee. Mr. Pagano served as a senior corporate partner of Simpson Thacher & Bartlett LLP, a law firm, with a focus on capital markets transactions and public company advisory matters from 1981 until his retirement at the end of 2012. Mr. Pagano earned his law degree, cum laude, from Harvard Law School and his B.S. in Engineering, summa cum laude, from Lehigh University and an M.S. in Engineering from the University of California, Berkeley. 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. Mr. Pagano currently also serves as a director of L-3 Communications Holdings, Inc., a publicly traded defense company, and Hovnanian Enterprises, Inc., a publicly traded homebuilding company.

Oliver G. Richard, III is a director of our general partner and serves as a member of the Audit Committee and Conflicts Committee. Mr. Richard has served as Chairman of Cleanfuel USA, an alternative vehicular fuel company, since September 2007 and, for the past five years, he has been 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. Mr. Richard was a Commissioner on the Federal Energy Regulatory Commission from 1982 until 1985. Mr. Richard received a B.S. in Journalism and 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. Mr. Richard currently serves as a director of Buckeye Partners, L.P., a publicly traded petroleum product pipeline and terminal company, and American Electric Power Company, Inc., a publicly traded electric utility.

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 directors, officers and employees of the Company, 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.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Exchange Act requires the directors and executive officers of our general partner and persons who own more than 10% of a registered class of our equity securities to file initial reports of ownership and reports of changes in ownership with the SEC. Such persons are required by SEC regulation to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of such forms furnished to us and written representations from the directors and executive officers of our general partner (or otherwise based on our knowledge), we believe that all Section 16(a) filing requirements were met during 2015 in a timely manner.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Our general partner has paid no cash compensation to its executive officers since its inception. All of the executive officers of our general partner are also executive officers of Cheniere. Cheniere compensates these officers for the performance of their duties as executive officers of Cheniere, which includes managing our partnership. Cheniere does not allocate this compensation between services for us and services for Cheniere and its affiliates. Instead, an affiliate of Cheniere provides us various general and administrative services for our benefit, such as technical, commercial, regulatory, financial, accounting, treasury, tax and legal staffing and related support services, pursuant to a services agreement for which we pay a quarterly non-accountable overhead reimbursement charge of $2.8 million (adjusted for inflation). For a description of the services agreement, see Note 11—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:
Neal A. Shear
R. Keith Teague
Michael J. Wortley
James R. Ball
John-Paul Munfa
Meg A. Gentle
Sean T. Klimczak

Lon McCain
Philip Meier
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. Other than Mr. Shear who served as Chairman of the compensation committee of Cheniere, 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 2015.

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; and $2,500 per meeting for the non-employee members of the executive committee, including the chairman. 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, when they joined the board of directors Messrs. Ball, McCain, Pagano and Richard each received 12,000 phantom units pursuant to the terms of the Cheniere Energy Partners, L.P. Long-Term Incentive Plan. The grant date for each grant is as follows: May 29, 2007 for Mr. McCain, September 7, 2012 for Messrs. Ball and Richard and December 7, 2012 for Mr. Pagano. Each of these directors will receive an additional 3,000 phantom units annually on each anniversary of the grant date. 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. Foley and Mr. Klimczak serve as Senior Managing Director 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 (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 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 2015 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
Neal A. Shear (2)	$—	$—	$—	$ —	$ —	$ —	$—
R. Keith Teague (2)	—	—	—	—	—	—	—
Michael J. Wortley (2)	—	—	—	—	—	—	—

James R. Ball (3)	85,000	87,360	—	—	—	—	172,360
David I. Foley (4)							
Meg A. Gentle (2)	—	—	—	—	—	—	—
Sean T. Klimczak (4)	—	—	—	—	—	—	—
Lon McCain (5)	100,000	99,570	—	—	—	—	199,570
Philip Meier (6)	—	—	—	—	—	—	—
John-Paul Munfa (4)	—	—	—	—	—	—	—
Vincent Pagano, Jr. (7)	95,000	65,610	—	—	—	—	160,610
Oliver G. Richard, III (8)	85,000	87,360	—	—	—	—	172,360
Charif Souki (2)	—	—	—	—	—	—	—

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(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. Teague served as an executive officer of our general partner and as an executive officer of Cheniere during fiscal year 2015. Ms. Gentle served as an executive officer of Cheniere during fiscal year 2015. Mr. Wortley served as an executive officer of our general partner and as an executive officer of Cheniere during fiscal year 2015. Mr. Shear served as an executive officer of our general partner since December 13, 2015 and as an executive officer of Cheniere since December 12, 2015. Mr. Souki served as an executive officer of our general partner from January 1 until December 13, 2015 and as an executive officer of Cheniere from January 1 until December 12, 2015. Cheniere compensates these officers for the performance of their duties as executive officers of Cheniere, which includes managing our partnership. They do not receive additional compensation for service as directors.

(3) Mr. Ball was granted 3,000 phantom units in 2015 with a grant date fair value of $87,360. In addition, Mr. Ball received $87,360 in cash and 1,500 common units on account of 4,500 phantom units granted in earlier years that vested in 2015. As of December 31, 2015, he held 9,750 phantom units and 2,250 common units for a total of 12,000 units.

(4) Messrs. Foley and Klimczak serve as Senior Managing Directors, and Mr. Munfa is a Managing Director, in the Private Equity Group of Blackstone Group. They do not receive additional compensation for service as directors.

(5) Mr. McCain was granted 3,000 phantom units in 2015 with a grant date fair value of $99,570. In addition, Mr. McCain received $74,678 in cash and 750 common units on account of 3,000 phantom units granted in earlier years that vested in 2015. As of December 31, 2015, he held 7,500 phantom units and 750 common units for a total of 8,250 units.

(6) 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.

(7) Mr. Pagano was granted 3,000 phantom units in 2015 with a grant date fair value of $65,610. In addition, Mr. Pagano received $82,013 in cash and 750 common units on account of 4,500 phantom units granted in earlier years that vested in 2015. As of December 31, 2015, he held 9,750 phantom units and 1,125 common units for a total of 10,875 units.

(8) Mr. Richard was granted 3,000 phantom units in 2015 with a grant date fair value of $87,360. In addition, Mr. Richard received $109,200 in cash and 750 common units on account of 4,500 phantom units granted in earlier years that vested in 2015. As of December 31, 2015, he held 9,750 phantom units and 750 common units for a total of 10,500 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 12, 2016, the following units were outstanding: 57,103,598 common units, 135,383,831 subordinated units and 145,333,334 Class B units. In addition, as of February 12, 2016, there were 6,893,811 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, Class B units, subordinated units and/or general partner units as of February 12, 2016:

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned		Class B Units Beneficially Owned	Percentage of Class B Units Beneficially Owned		Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned		Percentage of Total Securities Beneficially Owned	
Cheniere Energy, Inc. (1)	11,963,488	21	%	45,333,334	31	%	135,383,831	100	%	58	%
Cheniere Energy Partners LP Holdings, LLC	11,963,488	21	%	45,333,334	31	%	135,383,831	100	%	56	%
Blackstone Group (2)	3,758,003	7	%	—	—	%	—	—		1	%
Blackstone CQP Holdco	—	—	%	100,000,000	69	%	—	—		29	%
UBS Group AG (3)	2,855,220	5	%	—	—		—	—		1	%

(1) Cheniere Energy, Inc. is the parent company of Cheniere Energy Partners LP Holdings, LLC and may, therefore, be deemed to beneficially own the units held by Cheniere Energy Partners LP Holdings, LLC. Cheniere Energy, Inc. owns approximately 80% of the outstanding common shares of Cheniere Energy Partners LP Holdings, LLC, as well as the sole share of that entity authorized to elect its directors. Cheniere Energy, Inc. also owns 6,893,811 of our general partner units.

(2) Information is based solely on a Schedule 13D/A filed with the SEC on January 15, 2016 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. Blackstone CQP Common Holdco L.P. is the record holder of 1,101,169 common units. GSO Coastline Credit Partners LP, GSO Credit-A Partners LP and GSO Palmetto Opportunistic Investment Partners LP are the record holders of 53,057, 963,855 and 963,855 common units, respectively. GSO Credit Alpha Fund AIV-2 LP is the record owner of 383,747 common units. GSO Special Situations Fund LP, GSO Special Situations Master Fund LP and GSO

Special Situations Overseas Master Fund Ltd. are the record holders of 95,696, 96,943 and 99,681 common units, respectively. The address of the various persons identified in this footnote is 345 Park Avenue, New York, New York 10154.

(3) Information is based on a Schedule 13G filed with the SEC on February 9, 2016 by UBS Group AG directly and on behalf of certain subsidiaries, UBS AG London Branch, UBS Financial Services Inc., and UBS Securities LLC. UBS Group AG has shared power to vote and dispose of the shares beneficially owned. The address of UBS Group AG is Bahnhofstrasse 45, PO Box CH-8021, Zurich, Switzerland.

Directors and Executive Officers

The following table sets forth information with respect to our common units owned of record and beneficially as of February 12, 2016, by each director and executive officer of our general partner and by all directors and executive officers of our general partner as a group. On February 12, 2016, the directors and executive officers of Cheniere Partners beneficially owned an aggregate of 418,010 common units (approximately 1% of the outstanding common units at the time).

The table also presents the ownership of common shares of Cheniere Energy Partners LP Holdings, LLC and shares of common stock of Cheniere Energy, Inc. owned of record or beneficially as of February 12, 2016, by each director and executive officer of our general partner and by all directors and executive officers of our general partner as a group. Cheniere Energy Partners LP Holdings, LLC owns a majority interest in Cheniere Partners. Cheniere Energy, Inc. owns a majority interest in Cheniere Energy Partners LP Holdings, LLC. As of February 12, 2016, Cheniere Energy Partners LP Holdings, LLC had 231,700,000 common shares outstanding and Cheniere Energy, Inc. had 235,634,507 shares of common stock outstanding.

	Cheniere Energy Partners, L.P.				Cheniere Energy Partners LP Holdings, LLC		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	Amount and Nature of Beneficial Ownership		Percent of Class	
Neal A. Shear (1)	—		—		—	—	8,697		*	
Charif Souki (1)	400,100	(2)	1	%	—	—	2,983,026		1	%
R. Keith Teague	—		—		—	—	613,158		*	
Meg A. Gentle	8,035		*		—	—	1,351,907		1	%
James R. Ball	2,250		*		—	—	—		—	
David I. Foley (3)										
John-Paul Munfa (3)	—		—		—	—	—		—	
Sean T. Klimczak (3)	—		—		—	—	—		—	
Lon McCain	750		*		—	—	—		—	
Vincent Pagano, Jr.	1,125		*		—	—	—		—	
Michael J. Wortley	5,000		*		—	—	422,005	(4)	*	
Philip Meier (3)	—		—		—	—	—		—	
Oliver G. Richard, III	750		*		—	—	—		—	
All directors and executive officers as a group (13 persons)	418,010		1	%	—	—	5,378,793		2	%

* Less than 1%

(1) As of December 13, 2015, Mr. Shear was appointed as Chairman of the Board and interim Chief Executive Officer of our general partner, replacing Mr. Souki.

(2) Includes 400,100 units held by Mr. Souki's wife.

(3) Messrs. Foley, Munfa, Klimczak and Meier were appointed as directors of our general partner pursuant to the rights of Blackstone CQP Holdco under the Third Amended and Restated Limited Liability Company Agreement of our general partner to appoint certain directors to the board of directors of our general partner.

(4) Includes 1,500 shares issuable upon exercise of currently exercisable stock options held by Mr. Wortley.

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, 2015 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	19,125	N/A	1,231,250
Total	19,125	N/A	1,231,250

(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 11—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 Chief 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.

ISDA Master Agreement

In September 2007, Cheniere Marketing and SPLNG entered into an International Swaps and Derivatives Association ("ISDA") Master Agreement that provides SPLNG with the ability to hedge its future price risk from time to time. The ISDA Master Agreement was entered into in the event SPLNG chooses to hedge some of its LNG purchases or gas sales and elects to implement such hedges through Cheniere Marketing, which already has ISDA agreements in place with third parties and accounts with futures brokers. There are no current transactions under this agreement. No amounts were paid to Cheniere Marketing under this agreement during the year ended December 31, 2015.

LNG Terminal Export Agreement

In January 2010, SPLNG and Cheniere Marketing entered into 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 in the year ended December 31, 2015.

The following related-party transactions were not approved by the board of directors or audit committee of our general partner:

Agreement to Fund SPLNG's Cooperative Endeavor Agreements ("CEAs")

In July 2007, SPLNG executed CEAs with various Cameron Parish, Louisiana taxing authorities and a related agreement with Cheniere Marketing, as described in Note 11—Related Party Transactions of our Notes to Consolidated Financial Statements. During the year ended December 31, 2015, Cheniere Marketing paid Sabine Pass LNG $2.5 million under the 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 of $375,000 per year and an annual performance consulting fee of up to $200,000 per year in Blackstone CQP Holdco's discretion. The annual performance consulting fee with respect to 2015 was $125,000. 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.

In addition, Blackstone CQP Holdco agreed to pay Mr. Meier the following fees upon the substantial completion of each of Trains 1 through 4 of the Liquefaction Project, provided Mr. Meier continues to provide consulting services through such time: (a) upon the substantial completion of Train 1, an amount equal to the product of (1) 83,333, (2) 15% and (3) the fair market value of one of our common units as of that date; (b) upon the substantial completion of Train 2, an amount equal to the product of (1) 83,333, (2) 15% and (3) the fair market value of one of our common units as of that date; (c) upon the substantial completion of Train 3, an amount equal to the product of (1) 83,333, (2) 30% and (3) the fair market value of one of our common units as of that date; and (d) upon the substantial completion of Train 4, an amount equal to (1) the product of 83,333 and the fair market value of one of our common units as of that date, less (2) the sum of all payments made with respect to the substantial completion of each of Trains 1 through 3.

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 2015 under the Blackstone Consultant Letter Agreement.

Independent Directors

Because we are a limited partnership, the NYSE MKT 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 MKT. The board of our general partner has determined that Messrs. Ball, McCain, Pagano and Richard are independent directors in accordance with the following NYSE MKT 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 year ended December 31, 2015 and 2014. The following table (in thousands) sets forth the fees paid to KPMG LLP for professional services rendered for 2015 and 2014:

	Fiscal 2015	Fiscal 2014
Audit Fees	$2,505	$2,265

Audit Fees—Audit fees for 2015 and 2014 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 2015 and 2014.

Tax Fees—There were no tax fees in 2015 and 2014.

Other Fees—There were no other fees in 2015 and 2014.

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, 2015 and 2014 were pre-approved.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements and Exhibits

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

(2) Financial Statement Schedules:

(3) Exhibits:

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

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

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

Exhibit No.	Description
2.1	Contribution and Conveyance Agreement (Incorporated by reference to Exhibit 10.4 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on March 26, 2007)
2.2	Amended and Restated Purchase and Sale Agreement, dated as of August 9, 2012, by and among Cheniere Energy Partners, L.P., Cheniere Pipeline Company, Grand Cheniere Pipeline, LLC and Cheniere Energy, Inc. (Incorporated by reference to Exhibit 10.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012)

Exhibit No.	Description
3.1	Certificate of Limited Partnership of Cheniere Energy Partners, L.P. (Incorporated by reference to Exhibit 3.1 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-139572), filed on December 21, 2006)
3.2	Third Amended and Restated Agreement of Limited Partnership of Cheniere Energy Partners, L.P., dated as of August 9, 2012 (Incorporated by reference to Exhibit 3.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012)
3.3	Certificate of Formation of Cheniere Energy Partners GP, LLC (Incorporated by reference to Exhibit 3.3 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-139572), filed on December 21, 2006)
3.4	Third Amended and Restated Limited Liability Company Agreement of Cheniere Energy Partners GP, LLC, dated as of August 9, 2012 (Incorporated by reference to Exhibit 3.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012)
4.1	Form of common unit certificate (Included as Exhibit A to Exhibit 3.2 above)
4.2	Indenture, dated as of November 9, 2006, by and among Sabine Pass LNG, L.P., as issuer, the guarantors as defined therein and The Bank of New York, as trustee (Incorporated by reference to Exhibit 4.1 to Cheniere's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
4.3	Form of 7.50% Senior Secured Note due 2016 (Included as Exhibit A1 to Exhibit 4.2 above)
4.4	Indenture, dated as of October 16, 2012, by and among Sabine Pass LNG, L.P., the guarantors that may become party thereto from time to time and The Bank of New York Mellon, as trustee (Incorporated by reference to Exhibit 4.1 to SPLNG's Current Report on Form 8-K (SEC File No. 333-138916), filed on October 19, 2012)
4.5	Form of 6.5% Senior Secured Note due 2020 (Included as Exhibit A1 to Exhibit 4.4 above)
4.6	Indenture, dated as of February 1, 2013, by and among Sabine Pass Liquefaction, LLC, the guarantors that may become party thereto from time to time and The Bank of New York Mellon, as trustee (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on February 4, 2013)
4.7	Form of 5.625% Senior Secured Note due 2021 (Included as Exhibit A-1 to Exhibit 4.6 above)
4.8	First Supplemental Indenture, dated as of April 16, 2013, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on April 16, 2013)
4.9	Second Supplemental Indenture, dated as of April 16, 2013, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on April 16, 2013)
4.10	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.9 above)
4.11	Third Supplemental Indenture, dated as of November 25, 2013, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on November 25, 2013)
4.12	Form of 6.25% Senior Secured Note due 2022 (Included as Exhibit A-1 to Exhibit 4.11 above)
4.13	Fourth Supplemental Indenture, dated as of May 20, 2014, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on May 22, 2014)
4.14	Form of 5.750% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.13 above)
4.15	Fifth Supplemental Indenture, dated as of May 20, 2014, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on May 22, 2014)
4.16	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.15 above)
4.17	Sixth Supplemental Indenture, dated as of March 3, 2015, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to the

	Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on March 3, 2015)
4.18	Form of 5.625% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.17 above)
10.1	LNG Terminal Use Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.1 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)

Exhibit No.	Description
10.2	Amendment of LNG Terminal Use Agreement, dated January 24, 2005, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.40 to Cheniere's Annual Report on Form 10-K (SEC File No. 001-16383), filed on March 10, 2005)
10.3	Amendment of LNG Terminal Use Agreement, dated June 15, 2010, by and between Total Gas & Power North America, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 6, 2010)
10.4	Omnibus Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.5	Parent Guarantee, dated as of November 5, 2004, by Total S.A. in favor of Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.3 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.6	Letter Agreement, dated September 11, 2012, between Total Gas & Power North America, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.7	LNG Terminal Use Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.4 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.8	Amendment to LNG Terminal Use Agreement, dated December 1, 2005, by and between Chevron U.S.A., Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.28 to SPLNG's Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006)
10.9	Amendment of LNG Terminal Use Agreement, dated June 16, 2010, by and between Chevron U.S.A. Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.3 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 6, 2010)
10.10	Omnibus Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.5 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.11	Guaranty Agreement, dated as of December 15, 2004, from ChevronTexaco Corporation to Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.12 to SPLNG's Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006)
10.12	Second Amended and Restated LNG Terminal Use Agreement, dated as of July 31, 2012, between Sabine Pass LNG, L.P. and Sabine Pass Liquefaction, LLC (Incorporated by reference to Exhibit 10.1 to SPLNG's Current Report on Form 8-K (SEC File No. 333-138916), filed on August 6, 2012)
10.13	Letter Agreement, dated May 28, 2013, by and between Sabine Pass LNG, L.P. and Sabine Pass Liquefaction, LLC (Incorporated by reference to Exhibit 10.1 to SPLNG's Quarterly Report on Form 10-Q (SEC File No. 333-138916), filed on August 2, 2013)
10.14	Guarantee Agreement, dated as of July 31, 2012, by Cheniere Energy Partners, L.P. in favor of Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to SPLNG's Current Report on Form 8-K (SEC File No. 333-138916), filed on August 6, 2012)
10.15	Collateral Trust Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., The Bank of New York, as collateral trustee, Sabine Pass LNG-GP, Inc. and Sabine Pass LNG-LP, LLC (Incorporated by reference to Exhibit 10.1 to Cheniere's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.16	Amended and Restated Parity Lien Security Agreement, dated November 9, 2006, by and between Sabine Pass LNG, L.P. and The Bank of New York, as collateral trustee (Incorporated by reference to Exhibit 10.2 to Cheniere's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.17	Third Amended and Restated Multiple Indebtedness Mortgage, Assignment of Rents and Leases and Security Agreement, dated November 9, 2006, by Sabine Pass LNG, L.P. to and for the benefit of

	The Bank of New York, as collateral trustee (Incorporated by reference to Exhibit 10.3 to Cheniere's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.18	Amended and Restated Parity Lien Pledge Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., Sabine Pass LNG-GP, Inc., Sabine Pass LNG-LP, LLC and The Bank of New York, as collateral trustee (Incorporated by reference to Exhibit 10.4 to Cheniere's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)

Exhibit No.	Description
10.19	Security Deposit Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., The Bank of New York, as collateral trustee, and The Bank of New York, as depositary agent (Incorporated by reference to Exhibit 10.5 to Cheniere's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.20	Second Amended and Restated Credit Agreement (Term Loan A), dated as of June 30, 2015, among Sabine Pass Liquefaction, LLC, as Borrower, Société Générale, as the Commercial Banks Facility Agent and the Common Security Trustee, and the lenders from time to time party thereto (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on July 1, 2015)
10.21	Second Amended and Restated Common Terms Agreement, dated as of June 30, 2015, among Sabine Pass Liquefaction, LLC, as Borrower, the representatives and agents from time to time parties thereto, and Société Générale, as the Common Security Trustee and Intercreditor Agent (Incorporated by reference to Exhibit 10.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on July 1, 2015)
10.22	Amended and Restated KSURE Covered Facility Agreement, dated as of June 30, 2015, among Sabine Pass Liquefaction, LLC, as Borrower, The Korea Development Bank, New York Branch, as the KSURE Covered Facility Agent, Société Générale, as the Common Security Trustee, and the lenders from time to time party thereto (Incorporated by reference to Exhibit 10.5 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on July 1, 2015)
10.23	KEXIM Direct Facility Agreement, dated as of June 30, 2015, among Sabine Pass Liquefaction, LLC, as Borrower, Shinhan Bank New York Branch, as the KEXIM Facility Agent, Société Générale, as the Common Security Trustee, and The Export-Import Bank of Korea, a governmental financial institution of the Republic of Korea ("KEXIM"), as the KEXIM Direct Facility Lender, Joint Lead Arranger and Joint Lead Bookrunner (Incorporated by reference to Exhibit 10.3 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on July 1, 2015)
10.24	KEXIM Covered Facility Agreement, dated as of June 30, 2015, among Sabine Pass Liquefaction, LLC, as Borrower, Shinhan Bank New York Branch, as the KEXIM Facility Agent, Société Générale, as the Common Security Trustee, KEXIM and the lenders from time to time party thereto (Incorporated by reference to Exhibit 10.4 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on July 1, 2015)
10.25	Omnibus Amendment, dated as of September 24, 2015, to the Second Amended and Restated Common Terms Agreement among Sabine Pass Liquefaction, LLC, as Borrower, the representatives and agents from time to time parties thereto, and Société Générale, as the Common Security Trustee and Intercreditor Agent (Incorporated by reference to Exhibit 10.6 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on October 30, 2015)
10.26	Credit Agreement, dated as of May 28, 2013, among Cheniere Creole Trail Pipeline, L.P., as borrower, the lenders party thereto from time to time, Morgan Stanley Senior Funding, Inc., as administrative agent, The Bank of New York Mellon, as collateral agent, and The Bank of New York Mellon, as depositary bank (Incorporated by reference to Exhibit 10.6 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on May 29, 2013)
10.27	Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, dated as of September 4, 2015, among Sabine Pass Liquefaction, LLC, 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 (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on September 11, 2015)
10.28†	Form of Director Units Option Agreement for employees and consultants (four-year) (Incorporated by reference to Exhibit 10.41 to the Partnership's Registration Statement on Form S-1 (SEC File No.

	333-139572), filed on March 2, 2007)
10.29†	Form of Phantom Units Agreement for employees, consultants and directors (four-year) (Incorporated by reference to Exhibit 10.44 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)
10.30†	Form of Phantom Units Agreement for employees, consultants and directors (three-year) (Incorporated by reference to Exhibit 10.45 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)
10.31†	Form of Restricted Units Agreement for employees, consultants and directors (four-year) (Incorporated by reference to Exhibit 10.40 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)

Exhibit No.	Description
10.32†	Form of Restricted Units Agreement for employees, consultants and directors (three-year) (Incorporated by reference to Exhibit 10.39 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)
10.33†	Form of Units Option Agreement for employees and consultants (four-year) (Incorporated by reference to Exhibit 10.43 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)
10.34†	Form of Units Option Agreement for employees and consultants (three-year) (Incorporated by reference to Exhibit 10.42 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)
10.35†	Cheniere Energy Partners, L.P. 2007 Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.3 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on March 26, 2007)
10.36†	Form of Phantom Units Agreement (Incorporated by reference to Exhibit 10.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on June 4, 2007)
10.37†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (2012 Reload Award) (Incorporated by reference to Exhibit 10.9 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.38†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.8 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.39†	Form of Amendment to Phantom Units Agreement (Incorporated by reference to Exhibit 10.7 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.40†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Units Settlement) (Incorporated by reference to Exhibit 10.41 to the Partnership's Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 19, 2015)
10.41†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Reload Units Settlement) (Incorporated by reference to Exhibit 10.42 to the Partnership's Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 19, 2015)
10.42*†	Form of Indemnification Agreement for officers and/or directors of Cheniere Energy Partners GP, LLC
10.43	LNG Lease Agreement, dated June 24, 2008, between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.7 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 11, 2008)
10.44	LNG Lease Agreement, dated September 30, 2011, by and between Cheniere Marketing, LLC and Cheniere Energy Investments, LLC (Incorporated by reference to Exhibit 10.3 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 7, 2011)
10.45	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on November 14, 2011)
10.46	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-0001 EPC Terms and Conditions, dated May 1, 2012, (ii) the Change Order CO-0002 Heavies Removal Unit, dated May 23, 2012, (iii) the Change Order CO-0003 LNTP, dated June 6, 2012, (iv) the Change Order CO-0004 Addition of Inlet Air Humidification, dated July 10, 2012, (v) the Change Order CO-0005 Replace Natural Gas Generators with Diesel Generators, dated July 10, 2012, (vi) the

Change Order CO-0006 Flange Reduction and Valve Positioners, dated June 20, 2012, and (vii) the Change Order CO-0007 Relocation of Temporary Facilities, Power Poles Relocation Reimbursement, and Duck Blind Road Improvement Reimbursement, dated July 13, 2012 (Incorporated by reference to Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on August 3, 2012)

Exhibit No.	Description
10.47	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-0008 Delay in Full Placement of Insurance, dated July 27, 2012, (ii) the Change Order CO-0009 HAZOP Action Items, dated July 31, 2012, (iii) the Change Order CO-00010 Fuel Provisional Sum, dated August 8, 2012, (iv) the Change Order CO-00011 Currency Provisional Sum, dated August 8, 2012, (v) the Change Order CO-00012 Delay in NTP, dated August 8, 2012, and (vi) the Change Order CO-00013 Early EPC Work Credit, dated August 29, 2012 (Incorporated by reference to Exhibit 10.2 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.48	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00014 Bundle of Changes, dated September 5, 2012, (ii) the Change Order CO-00015 Static Mixer, Air Cooler Walkways, etc., dated November 8, 2012, (iii) the Change Order CO-0016 Delay in Full Placement of Insurance, dated October 29, 2012, (iv) the Change Order CO-00017 Condensate Header, dated December 3, 2012 and (v) the Change Order CO-00018 Increase in Power Requirements, dated January 17, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.26 to the Partnership's Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013)
10.49	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00019 Delete Tank 6 Scope of Work, dated February 27, 2013 and (ii) the Change Order CO-00020 Modification to Builder's Risk Insurance Sum Insured Value, dated March 14, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.2 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on May 3, 2013)
10.50	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00021 Increase to Insurance Provisional Sum, dated April 17, 2013, (ii) the Change Order CO-00022 Removal of LNG Static Mixer Scope, dated May 8, 2013, (iii) the Change Order CO-00023 Revised LNG Rundown Line, dated May 30, 2013, (iv) the Change Order CO-00024 Reroute Condensate Header, Substation HVAC Stacks, Inlet Metering Station Pile Driving, dated June 11, 2013 and (v) the Change Order CO-00025 Feed Gas Connection Modifications, dated June 11, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.45 to Amendment No. 1 to Cheniere Holdings' Registration Statement on Form S-1/A (SEC File No. 333-191298), filed on October 18, 2013)
10.51	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00026 Bundle of Changes, dated June 28, 2013, (ii) the Change Order CO-00027 16" Water Pumps, dated July 12, 2013, (iii) the Change Order CO-00028 HRU Operability, dated July 26, 2013, (iv) the Change Order CO-00029 Belleville Washers, dated August 14, 2013 and (v) the Change Order CO-00030 Soils Preparation Provisional Sum Transfer, dated August 29, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential

	treatment.) (Incorporated by reference to Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 8, 2013)
10.52	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00031 LNG Intank Pump Replacement Scope Reduction/OSBL Additional Piling for the Cathodic Protection Rectifier Platform and Drum Storage Shelter dated October 15, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.35 to Amendment No. 2 to SPL's Registration Statement on Form S-4/A (SEC File No. 333-192373), filed on January 28, 2014)
10.53	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00032 Intra-Plant Feed Gas Header and Jefferson Davis Electrical Distribution, dated January 9, 2014, (ii) the Change Order CO-00033 Revised EPC Agreement Attachments S & T, dated March 24, 2014 and (iii) the Change Order CO-00034 Greenfield/Brownfield Demarcation Adjustment, dated February 19, 2014 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on May 1, 2014)

Exhibit No.	Description
10.54	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00035 Resolution of FERC Open Items, Additional FERC Support Hours and Greenfield/Brownfield Milestone Adjustment, dated May 9, 2014 (Incorporated by reference to Exhibit 10.3 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on July 31, 2014)
10.55	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00036 Future Tie-Ins and Jeff Davis Invoices, dated July 9, 2014 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.23 to SPL's Registration Statement on Form S-4 (SEC File No. 333-198358), filed on August 26, 2014)
10.56	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00037 Performance and Attendance Bonus (PAB) Incentive Program Provisional Sum, dated October 31, 2014 and (ii) the Change Order CO-00038 Control Room Modifications and Miscellaneous Items, dated January 6, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.26 to SPL's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 19, 2015)
10.57	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00039 Increase to Existing Facility Labor Provisional Sum and Decrease to Sales and Use Tax Provisional Sum, dated February 12, 2015 and (ii) the Change Order CO-00040 Load Shedding and LNG Tank Tie-In Crane, dated February 24, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.2 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on April 30, 2015)
10.58	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00041 Additional Building Utility Tie-in Packages and Fire and Gas Modifications, dated April 9, 2015 (Incorporated by reference to Exhibit 10.2 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on July 30, 2015)
10.59	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00042 Platform Design Modifications, Compressor Oil Fills, Additional Building Modifications, dated October 16, 2015, and (ii) the Change Order CO-00043 Soil Provisional Sum Closure, dated December 2, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.32 to SPL's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 18, 2016)
10.60	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated December 20, 2012, by and between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been

	omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on December 27, 2012)
10.61	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-0001 Electrical Station HVAC Stacks, dated June 4, 2013, (ii) the Change Order CO-0002 Revised LNG Rundown Lines, dated May 30, 2013, (iii) the Change Order CO-0003 Currency Provisional Sum Closure, dated May 29, 2013 and (iv) the Change Order CO-0004 Fuel Provisional Sum Closure, dated May 29, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.48 to Amendment No. 1 to Cheniere Holdings' Registration Statement on Form S-1/A (SEC File No. 333-191298), filed on October 18, 2013)

Exhibit No.	Description
10.62	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-0005 Credit to EPC Contract Value for TSA Work, dated June 24, 2013, (ii) the Change Order CO-0006 HRU Operability with Lean Gas & Controls Upgrade and Ultrasonic Meter Configuration and Calibration, dated July 26, 2013, (iii) the Change Order CO-0007 Additional Belleville Washers, dated August 15, 2013, (iv) the Change Order CO-0008 GTG Switchgear Arrangement/Upgrade Fuel Gas Heater System, dated August 26, 2013, and (v) the Change Order CO-0009 Soils Preparation Provisional Sum Transfer and Closure, dated August 26, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.49 to Amendment No. 1 to Cheniere Holdings' Registration Statement on Form S-1/A (SEC File No. 333-191298), filed on October 18, 2013)
10.63	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00010 Insurance Provisional Sum Adjustment, dated January 23, 2014, (ii) the Change Order CO-00011 Additional Stage 2 GTGs, dated January 23, 2014, (iii) the Change Order CO-0012 Lien and Claim Waiver Modification, dated March 24, 2014 and (iv) the Change Order CO-00013 Revised Stage 2 EPC Agreement Attachments S&T, dated March 24, 2014 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.2 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on May 1, 2014)
10.64	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00014 Additional 13.8kv Circuit Breakers and Misc. Items, dated July 14, 2014 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.28 to SPL's Registration Statement on Form S-4 (SEC File No. 333-198358), filed on August 26, 2014)
10.65	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00015 Performance and Attendance Bonus (PAB) Incentive Program Provisional Sum, dated October 31, 2014 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.32 to SPL's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 19, 2015)
10.66	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00016 Louisiana Sales and Use Tax Provisional Sum Adjustment, dated February 12, 2015 and (ii) the Change Order CO-00017 Load Shedding Study and Scope Change, dated February 24, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.3 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on April 30, 2015)
10.67	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00018 Permanent Restroom Trailers and Installation of Tie-In for GTG Fuel Gas Interconnect,

	dated May 21, 2015 (Incorporated by reference to Exhibit 10.3 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on July 30, 2015)
10.68	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00019 East Meter Piping Tie-ins, dated August 26, 2015 (Incorporated by reference to Exhibit 10.1 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on October 30, 2015)
10.69	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated May 4, 2015, between Sabine Pass Liquefaction, LLC 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.) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K/A (SEC File No. 001-33366), filed on July 1, 2015)

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Exhibit No.	Description
10.70	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00001 Currency and Fuel Provisional Sum Adjustment, dated June 25, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.4 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on July 30, 2015)
10.71	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00002 Credit to EPC Contract Value for TSA Work, dated September 17, 2015 (Incorporated by reference to Exhibit 10.2 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on October 30, 2015)
10.72	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00003 Perimeter Fencing Scope Removal, East Meter Piping Scope Change, Additional Bathroom Facilities, dated November 18, 2015 (Incorporated by reference to Exhibit 10.45 to SPL's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 18, 2016)
10.73	LNG Sale and Purchase Agreement (FOB), dated November 21, 2011, between Sabine Pass Liquefaction, LLC (Seller) and Gas Natural Aprovisionamientos SDG S.A. (Buyer) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on November 21, 2011)
10.74	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated April 3, 2013, between Sabine Pass Liquefaction, LLC (Seller) and Gas Natural Aprovisionamientos SDG S.A. (Buyer) (Incorporated by reference to Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on May 3, 2013)
10.75	LNG Sale and Purchase Agreement (FOB), dated December 11, 2011, between Sabine Pass Liquefaction, LLC (Seller) and GAIL (India) Limited (Buyer) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on December 12, 2011)
10.76	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between Sabine Pass Liquefaction, LLC (Seller) and GAIL (India) Limited (Buyer) (Incorporated by reference to Exhibit 10.18 to the Partnership's Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013)
10.77	LNG Sale and Purchase Agreement (FOB), dated December 14, 2012, between Sabine Pass Liquefaction, LLC (Seller) and Total Gas & Power North America, Inc. (Buyer) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on December 17, 2012)
10.78	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated August 28, 2015, between Sabine Pass Liquefaction, LLC (Seller) and Total Gas & Power North America, Inc. (Buyer) (Incorporated by reference to Exhibit 10.4 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on October 30, 2015)
10.79	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated January 25, 2012, between Sabine Pass Liquefaction, LLC (Seller) and BG Gulf Coast LNG, LLC (Buyer) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on January 26, 2012)
10.80	LNG Sale and Purchase Agreement (FOB), dated January 30, 2012, between Sabine Pass Liquefaction, LLC (Seller) and Korea Gas Corporation (Buyer) (Incorporated by reference to Exhibit

	10.1 to the Partnership’s Current Report on Form 8-K (SEC File No. 001-33366), filed on January 30, 2012)
10.81	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between Sabine Pass Liquefaction, LLC (Seller) and Korea Gas Corporation (Buyer) (Incorporated by reference to Exhibit 10.19 to the Partnership’s Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013)
10.82	LNG Sale and Purchase Agreement (FOB), dated March 22, 2013, between Sabine Pass Liquefaction, LLC (Seller) and Centrica plc (Buyer) (Incorporated by reference to Exhibit 10.1 to the Partnership’s Current Report on Form 8-K (SEC File No. 001-33366), filed on March 25, 2013)
10.83	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated September 11, 2015, between Sabine Pass Liquefaction, LLC (Seller) and Centrica plc (Buyer) (Incorporated by reference to Exhibit 10.5 to the Partnership’s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on October 30, 2015)
10.84	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between Sabine Pass Liquefaction, LLC (Seller) and Cheniere Marketing, LLC (Buyer) (Incorporated by reference to Exhibit 10.1 to SPL’s Current Report on Form 8-K (SEC File No. 333-192373), filed on August 11, 2014)

Exhibit No.	Description
10.85	Management Services Agreement, dated May 14, 2012, by and between Cheniere LNG Terminals, LLC and Sabine Pass Liquefaction, LLC (Incorporated by reference to Exhibit 10.6 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)
10.86	Amendment to Management Services Agreement, dated September 28, 2015, between Cheniere LNG Terminals, LLC and Sabine Pass Liquefaction, LLC (Incorporated by reference to Exhibit 10.8 to Amendment No. 1 to SPL's Quarterly Report on Form 10-Q/A (SEC File No. 333-192373), filed on November 9, 2015)
10.87	Amended and Restated Management Services Agreement, dated as of August 9, 2012, by and between Cheniere LNG Terminals, LLC and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.6 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.88	Management Services Agreement, dated May 27, 2013, by and between Cheniere LNG Terminals, LLC and Cheniere Creole Trail Pipeline, L.P. (Incorporated by reference to Exhibit 10.2 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on August 2, 2013)
10.89	Operation and Maintenance Agreement (Sabine Pass Liquefaction Facilities), dated May 14, 2012, by and among Cheniere LNG O&M Services, LLC, Cheniere Energy Partners GP, LLC and Sabine Pass Liquefaction, LLC (Incorporated by reference to Exhibit 10.5 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)
10.90	Assignment and Assumption Agreement (Sabine Pass Liquefaction O&M Agreement), dated as of November 20, 2013, by and between Cheniere Energy Partners GP, LLC and Cheniere Energy Investments, LLC (Incorporated by reference to Exhibit 10.76 to Cheniere Holdings' Registration Statement on Form S-1 (SEC File No. 333-191298), filed on December 2, 2013)
10.91	Amendment to Operation and Maintenance Agreement (Sabine Pass Liquefaction Facilities), dated September 28, 2015, by and among Cheniere LNG O&M Services, LLC, Cheniere Energy Investments, LLC and Sabine Pass Liquefaction, LLC (Incorporated by reference to Exhibit 10.7 to Amendment No. 1 to SPL's Quarterly Report on Form 10-Q/A (SEC File No. 333-192373), filed on November 9, 2015)
10.92	Amended and Restated Operation and Maintenance Agreement (Sabine Pass LNG Facilities), dated as of August 9, 2012, by and among Cheniere LNG O&M Services, LLC, Cheniere Energy Partners GP, LLC and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.5 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.93	Assignment and Assumption Agreement (Sabine Pass LNG O&M Agreement), dated as of November 20, 2013, by and between Cheniere Energy Partners GP, LLC and Cheniere Energy Investments, LLC (Incorporated by reference to Exhibit 10.75 to Amendment No. 4 to Cheniere Holdings' Registration Statement on Form S-1/A (SEC File No. 333-191298), filed on December 2, 2013)
10.94	Amended and Restated Management and Administrative Services Agreement, dated as of August 9, 2012, by and between Cheniere Energy Partners, L.P., Cheniere LNG Terminals, LLC and Cheniere Energy, Inc. (Incorporated by reference to Exhibit 10.4 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.95	Amended and Restated Operation and Maintenance Services Agreement, dated May 27, 2013, by and between Cheniere Energy Partners GP, LLC and Cheniere Creole Trail Pipeline, L.P. (Incorporated by reference to Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on August 2, 2013)
10.96	Assignment and Assumption Agreement (Creole Trail O&M Agreement), dated as of November 20, 2013, between Cheniere Energy Partners GP, LLC and Cheniere Energy Investments, LLC (Incorporated by reference to Exhibit 10.74 to Cheniere Holdings' Registration Statement on Form S-1 (SEC File No. 333-191298), filed on December 2, 2013)
10.97	Waiver and Assignment of O&M Agreement; Amendment to Common Terms Agreement, dated November 20, 2013 (Incorporated by reference to Exhibit 10.77 to Cheniere Holdings' Registration

	Statement on Form S-1 (SEC File No. 333-191298), filed on December 2, 2013)
10.98	Payment Deferral Agreement (O&M Agreement), dated March 27, 2014, between Cheniere Energy Investments, LLC and Cheniere LNG O&M Services, LLC (Incorporated by reference to Exhibit 10.5 to Cheniere’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 1, 2014)
10.99	Cooperative Endeavor Agreement & Payment in Lieu of Tax Agreement, dated October 23, 2007, by and between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.7 to Cheniere’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 6, 2007)
10.100	Amended and Restated Services and Secondment Agreement, dated as of August 9, 2012, between Cheniere LNG O&M Services, LLC and Cheniere Energy Partners GP, LLC (Incorporated by reference to Exhibit 10.3 to the Partnership’s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)

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Exhibit No.	Description
10.101	Assignment and Assumption Agreement (Services and Secondment Agreement), dated as of November 20, 2013, by and between Cheniere Energy Partners GP, LLC and Cheniere Energy Investments, LLC (Incorporated by reference to Exhibit 10.73 to Cheniere Holdings' Registration Statement on Form S-1 (SEC File No. 333-191298), filed on December 2, 2013)
10.102	Unit Purchase Agreement, dated May 14, 2012, by and among Cheniere Energy Partners, L.P., Cheniere Energy, Inc. and Blackstone CQP Holdco LP (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)
10.103	Class B Unit Purchase Agreement, dated as of May 14, 2012, by and between Cheniere Energy Partners, L.P. and Cheniere LNG Terminals, LLC (Incorporated by reference to Exhibit 10.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)
10.104	First Amendment to Class B Unit Purchase Agreement, dated as of August 9, 2012, by and between Cheniere Energy Partners, L.P. and Cheniere Class B Units Holdings, LLC (Incorporated by reference to Exhibit 10.3 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012)
10.105	Subscription Agreement, dated May 14, 2012, by and between Cheniere Energy Partners, L.P. and Cheniere LNG Terminals, LLC (Incorporated by reference to Exhibit 10.4 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)
10.106	Letter Agreement, dated as of August 9, 2012, among Cheniere Energy, Inc., Cheniere Energy Partners, L.P. and Blackstone CQP Holdco LP (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012)
10.107	Investors' and Registration Rights Agreement, dated as of July 31, 2012, by and among Cheniere Energy, Inc., Cheniere Energy Partners, L.P., Cheniere Energy Partners GP, LLC, Blackstone CQP Holdco LP and the other investors party thereto from time to time (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on August 6, 2012)
21.1*	Subsidiaries of Cheniere Energy Partners, L.P.
23.1*	Consent of KPMG LLP
23.2*	Consent of Ernst & Young 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

* Filed herewith.
** Furnished herewith.
† Management contract or compensatory plan or arrangement

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT—

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED BALANCE SHEETS
(in thousands)

	December 31,	
	2015	2014
ASSETS		
Current assets		
Cash and cash equivalents	$109,950	$222,130
Accounts receivable—affiliates	—	9,568
Prepaid expenses and other	187	104
Total current assets	110,137	231,802
Investment in affiliates	617,749	902,612
Other non-current assets	953	123
Total assets	$728,839	$1,134,537
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accrued liabilities—affiliates	$14,750	$3,033
Other current liabilities	1,158	775
Total current liabilities	15,908	3,808
Partners' equity	712,931	1,130,729
Total liabilities and partners' equity	$728,839	$1,134,537

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

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED STATEMENTS OF OPERATIONS AND COMPREHENSIVE LOSS
(in thousands)

	Year Ended December 31,		
	2015	2014	2013
Operating costs and expenses	$5,737	$3,383	$3,041
Operating costs and expenses—affiliates	11,546	11,556	11,376
Loss from operations	(17,283)	(14,939)	(14,417)
Interest income	173	162	242
Equity loss of affiliates	(301,781)	(395,259)	(243,942)
Net loss	$(318,891)	$(410,036)	$(258,117)
Other comprehensive income attributable to affiliates	—	—	27,240
Comprehensive loss	$(318,891)	$(410,036)	$(230,877)

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

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2015	2014	2013
Cash flows from operating activities	$3,646	$(24,416)	$(13,056)
Cash flows from investing activities			
Investments in subsidiaries	(35,208)	(77,846)	(405,452)
Distributions received from affiliates, net	18,400	108,625	369,726
Purchase of Creole Trail Pipeline Business, net	—	—	(313,892)
Net cash provided by (used in) investing activities	(16,808)	30,779	(349,618)
Cash flows from financing activities:			
Distributions to owners	(99,018)	(99,015)	(91,386)
Proceeds from sale of partnership common and general partner units	—	—	375,897
Net cash provided by (used in) financing activities	(99,018)	(99,015)	284,511
Net decrease in cash and cash equivalents	(112,180)	(92,652)	(78,163)
Cash and cash equivalents—beginning of period	222,130	314,782	392,945
Cash and cash equivalents—end of period	$109,950	$222,130	$314,782

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

CHENIERE ENERGY PARTNERS, L.P.

NOTES TO CONDENSED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

A substantial amount of Cheniere Partners' operating, investing and financing activities are conducted by its affiliates. In the condensed financial statements, Cheniere Partners' investments in affiliates are presented under the equity method of accounting. Under this method, the assets and liabilities of affiliates are not consolidated. The investments in net assets of the affiliates are recorded in the balance sheets. The gain (loss) from operations of the affiliates is reported on a net basis as equity in net gains (losses) of affiliates.

In May 2013, we acquired Cheniere's ownership interest in the Creole Trail Pipeline Business, thereby providing us with ownership of a 94-mile pipeline interconnecting the Sabine Pass LNG terminal with a number of large interstate pipelines. The effect on reported equity on including the prior results of the Creole Trail Pipeline Business is reported as Investment in affiliates in our Condensed Balance Sheet and Equity loss of affiliates in our Condensed Statement of Operations. The purchase has been accounted for as a transfer of net assets between entities under common control. We recognize transfers of net assets between entities under common control at Cheniere's historical basis in the net assets sold. In addition, transfers of net assets between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information.

The condensed financial statements should be read in conjunction with Cheniere Partners' Consolidated Financial Statements.

NOTE 2—GUARANTEES

Guarantees on Behalf of CTPL

In May 2013, CTPL entered into a $400.0 million term loan facility (the "CTPL Term Loan"), which is being used to fund modifications to the Creole Trail Pipeline and for general business purposes. CTPL incurred $10.0 million of direct lender fees that were recorded as a debt discount. The CTPL Term Loan matures in 2017 when the full amount of the outstanding principal obligations must be repaid. CTPL's loans may be repaid, in whole or in part, at any time without premium or penalty. As of December 31, 2015, CTPL had borrowed the full amount of $400.0 million available under the CTPL Term Loan. Cheniere Partners has guaranteed on behalf of CTPL all principal, interest, costs, fees and expenses owed under the CTPL Term Loan.

NOTE 3—SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2015	2014	2013
Non-cash capital contributions (1)	$(301,781)	$(395,259)	$(225,792)
Non-cash capital contributions related to the Creole Trail Pipeline Business (1)	—	—	(18,150)

(1) Amounts represent equity gains (losses) of affiliates not funded by Cheniere Partners.

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/ Neal A. Shear
Neal A. Shear
Interim Chief Executive Officer
(Principal Executive Officer)
Date: February 18, 2016

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/ Neal A. Shear Neal A. Shear	Interim Chief Executive Officer, Chairman of the Board (Principal Executive Officer)	February 18, 2016
/s/ R. Keith Teague R. Keith Teague	President and Chief Operating Officer, Director (Principal Operating Officer)	February 18, 2016
/s/ Michael J. Wortley Michael J. Wortley	Senior Vice President and Chief Financial Officer, Director (Principal Financial Officer)	February 18, 2016
/s/ Leonard Travis Leonard Travis	Chief Accounting Officer (Principal Accounting Officer)	February 18, 2016
/s/ James R. Ball James R. Ball	Director	February 18, 2016
/s/ Meg A. Gentle Meg A. Gentle	Director	February 18, 2016
/s/ Sean T. Klimczak Sean T. Klimczak	Director	February 18, 2016
/s/ Lon McCain Lon McCain	Director	February 18, 2016
/s/ Philip Meier Philip Meier	Director	February 18, 2016
/s/ John-Paul Munfa John-Paul Munfa	Director	February 18, 2016

/s/ Vincent Pagano Jr. Vincent Pagano Jr.	Director	February 18, 2016
/s/ Oliver G. Richard, III Oliver G. Richard, III	Director	February 18, 2016