UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2018

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from______to______

Cheniere Energy Partners, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**001-33366**	**20-5913059**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

700 Milam Street, Suite 1900 **Houston, Texas**	**77002**
(Address of principal executive offices)	(Zip code)

(713) 375-5000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically 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 ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of May 1, 2018, the registrant had 348,619,292 common units and 135,383,831 subordinated units outstanding

CHENIERE ENERGY PARTNERS, L.P.

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DEFINITIONS

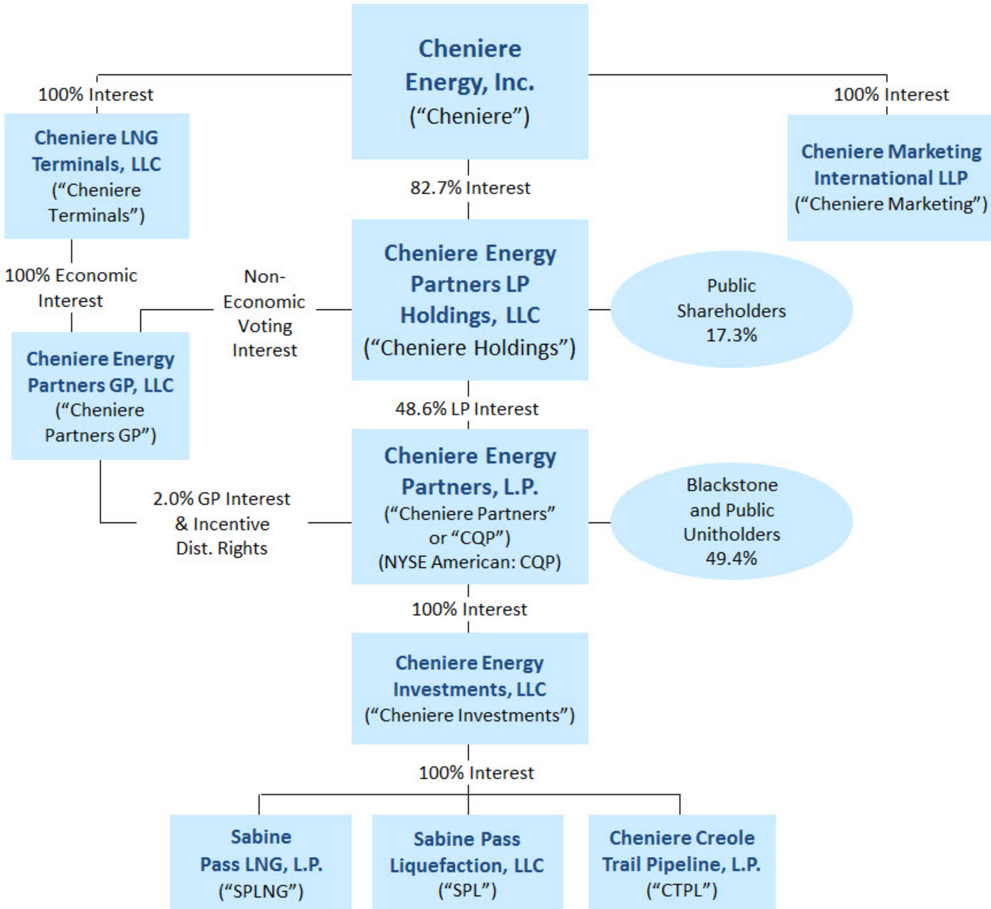
As used in this quarterly report, the terms listed below have the following meanings:

Common Industry and Other Terms

Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Bcf/yr	billion cubic feet per year
Bcfe	billion cubic feet equivalent
DOE	U.S. Department of Energy
EPC	engineering, procurement and construction
FERC	Federal Energy Regulatory Commission
FTA countries	countries with which the United States has a free trade agreement providing for national treatment for trade in natural gas
GAAP	generally accepted accounting principles in the United States
Henry Hub	the final settlement price (in USD per MMBtu) for the New York Mercantile Exchange's Henry Hub natural gas futures contract for the month in which a relevant cargo's delivery window is scheduled to begin
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas, a product of natural gas that, through a refrigeration process, has been cooled to a liquid state, which occupies a volume that is approximately 1/600th of its gaseous state
MMBtu	million British thermal units, an energy unit
mtpa	million tonnes per annum
non-FTA countries	countries with which the United States does not have a free trade agreement providing for national treatment for trade in natural gas and with which trade is permitted
SEC	U.S. Securities and Exchange Commission
SPA	LNG sale and purchase agreement
TBtu	trillion British thermal units, an energy unit
Train	an industrial facility comprised of a series of refrigerant compressor loops used to cool natural gas into LNG
TUA	terminal use agreement

Abbreviated Legal Entity Structure

The following diagram depicts our abbreviated legal entity structure as of March 31, 2018, including our ownership of certain subsidiaries, and the references to these entities used in this quarterly report:



Unless the context requires otherwise, references to "Cheniere Partners," "the Partnership," "we," "us" and "our" refer to Cheniere Energy Partners, L.P. and its consolidated subsidiaries, including SPLNG, SPL and CTPL.

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

PART I. **FINANCIAL INFORMATION**

ITEM 1. **CONSOLIDATED FINANCIAL STATEMENTS**

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in millions, except unit data)

	March 31, 2018	December 31, 2017
ASSETS	(unaudited)	
Current assets		
Cash and cash equivalents	$ —	$ —
Restricted cash	1,477	1,589
Accounts and other receivables	240	191
Accounts receivable—affiliate	114	163
Advances to affiliate	97	36
Inventory	83	95
Other current assets	54	65
Total current assets	2,065	2,139
Property, plant and equipment, net	15,145	15,139
Debt issuance costs, net	34	38
Non-current derivative assets	24	31
Other non-current assets, net	197	206
Total assets	$ 17,465	$ 17,553
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accounts payable	$ 11	$ 12
Accrued liabilities	509	637
Due to affiliates	30	68
Deferred revenue	95	111
Deferred revenue—affiliate	—	1
Derivative liabilities	4	—
Total current liabilities	649	829
Long-term debt, net	16,052	16,046
Non-current deferred revenue	—	1
Non-current derivative liabilities	3	3
Other non-current liabilities	11	10
Other non-current liabilities—affiliate	25	25
Partners' equity		
Common unitholders' interest (348.6 million units issued and outstanding at March 31, 2018 and December 31, 2017)	1,731	1,670
Subordinated unitholders' interest (135.4 million units issued and outstanding at March 31, 2018 and December 31, 2017)	(1,019)	(1,043)
General partner's interest (2% interest with 9.9 million units issued and outstanding at March 31, 2018 and December 31, 2017)	13	12
Total partners' equity	725	639
Total liabilities and partners' equity	$ 17,465	$ 17,553

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Revenues		
LNG revenues	$ 1,015	$ 492
LNG revenues—affiliate	503	331
Regasification revenues	65	65
Other revenues	10	2
Other revenues—affiliate	—	1
Total revenues	1,593	891
Operating costs and expenses		
Cost of sales (excluding depreciation and amortization expense shown separately below)	837	513
Operating and maintenance expense	95	50
Operating and maintenance expense—affiliate	26	18
General and administrative expense	4	3
General and administrative expense—affiliate	18	22
Depreciation and amortization expense	105	66
Total operating costs and expenses	1,085	672
Income from operations	508	219
Other income (expense)		
Interest expense, net of capitalized interest	(185)	(130)
Loss on early extinguishment of debt	—	(42)
Derivative gain, net	8	—
Other income	4	—
Total other expense	(173)	(172)
Net income	$ 335	$ 47
Basic and diluted net income (loss) per common unit	$ 0.67	$ (0.80)
Weighted average number of common units outstanding used for basic and diluted net income (loss) per common unit calculation	348.6	57.1

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS' EQUITY
(in millions)
(unaudited)

	Common Unitholders' Interest		Subordinated Unitholder's Interest		General Partner's Interest		Total Partners' Equity
	Units	Amount	Units	Amount	Units	Amount	
Balance at December 31, 2017	348.6	$ 1,670	135.4	$ (1,043)	9.9	$ 12	$ 639
Net income	—	236	—	92	—	7	335
Distributions	—	(175)	—	(68)	—	(6)	(249)
Balance at March 31, 2018	348.6	$ 1,731	135.4	$ (1,019)	9.9	$ 13	$ 725

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)
(unaudited)

	Three Months Ended March 31,	
	2018	2017
Cash flows from operating activities		
Net income	$ 335	$ 47
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	105	66
Amortization of debt issuance costs, deferred commitment fees, premium and discount	8	10
Loss on early extinguishment of debt	—	42
Total losses on derivatives, net	42	39
Net cash used for settlement of derivative instruments	(3)	(13)
Other	2	—
Changes in operating assets and liabilities:		
Accounts and other receivables	(50)	(11)
Accounts receivable—affiliate	48	59
Advances to affiliate	(56)	(41)
Inventory	12	17
Accounts payable and accrued liabilities	(69)	(38)
Due to affiliates	(25)	(68)
Deferred revenue	(18)	(11)
Other, net	—	1
Other, net—affiliate	—	16
Net cash provided by operating activities	331	115
Cash flows from investing activities		
Property, plant and equipment, net	(194)	(524)
Net cash used in investing activities	(194)	(524)
Cash flows from financing activities		
Proceeds from issuances of debt	—	2,314
Repayments of debt	—	(703)
Debt issuance and deferred financing costs	—	(26)
Distributions to owners	(249)	(25)
Net cash provided by (used in) financing activities	(249)	1,560
Net increase (decrease) in cash, cash equivalents and restricted cash	(112)	1,151
Cash, cash equivalents and restricted cash—beginning of period	1,589	605
Cash, cash equivalents and restricted cash—end of period	$ 1,477	$ 1,756

Balances per Consolidated Balance Sheet:

	March 31, 2018
Cash and cash equivalents	$ —
Restricted cash	1,477
Total cash, cash equivalents and restricted cash	$ 1,477

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

NOTE 1—NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Through SPL, we are developing, constructing and operating natural gas liquefaction facilities (the "Liquefaction Project") at the Sabine Pass LNG terminal located in Cameron Parish, Louisiana, on the Sabine-Neches Waterway less than four miles from the Gulf Coast. We plan to construct up to six Trains, which are in various stages of development, construction and operations. Trains 1 through 4 are operational, Train 5 is under construction and Train 6 is being commercialized and has all necessary regulatory approvals in place. 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 CTPL. We also recognize regasification revenues, which include LNG regasification capacity reservation fees that are received pursuant to our TUAs and tug services fees that are received by Sabine Pass Tug Services, LLC ("Tug Services"), a wholly owned subsidiary of SPLNG. Substantially all of our regasification revenues are received from our two long-term TUA customers.

Basis of Presentation

The accompanying unaudited Consolidated Financial Statements of Cheniere Partners have been prepared in accordance with GAAP for interim financial information and with Rule 10-01 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements and should be read in conjunction with the Consolidated Financial Statements and accompanying notes included in our annual report on Form 10-K for the year ended December 31, 2017. In our opinion, all adjustments, consisting only of normal recurring adjustments necessary for a fair presentation, have been included. Certain reclassifications have been made to conform prior period information to the current presentation. The reclassifications did not have a material effect on our consolidated financial position, results of operations or cash flows.

On January 1, 2018, we adopted ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, and subsequent amendments thereto ("ASC 606") using the full retrospective method. The adoption of ASC 606 represents a change in accounting principle that will provide financial statement readers with enhanced disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The adoption of ASC 606 did not impact our previously reported financial statements in any prior period nor did it result in a cumulative effect adjustment to retained earnings.

Results of operations for the three months ended March 31, 2018 are not necessarily indicative of the results of operations that will be realized for the year ending December 31, 2018.

We are not subject to either federal or state income tax, as our partners are taxed individually on their allocable share of our taxable income.

NOTE 2—UNITHOLDERS' EQUITY

The common units and subordinated units represent limited partner interests in us. The holders of the units are entitled to participate in partnership distributions and exercise the rights and privileges available to limited partners under our partnership agreement. Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement). Generally, our available cash is our cash on hand at the end of a quarter less the amount of any reserves established by our general partner. All distributions paid to date have been made from operating surplus as defined in the partnership agreement.

The holders of common units have the right to receive initial quarterly distributions of $0.425 per common unit, plus any arrearages thereon, before any distribution is made to the holders of the subordinated units. The holders of subordinated units will receive distributions only to the extent we have available cash above the initial quarterly distribution requirement for our common unitholders and general partner and certain reserves. Subordinated units will convert into common units on a one-for-one basis when we meet financial tests specified in the partnership agreement. Although common and subordinated unitholders are not obligated to fund losses of the Partnership, their capital accounts, which would be considered in allocating the net assets of the Partnership were it to be liquidated, continue to share in losses.

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

Cheniere Holdings, Blackstone CQP Holdco and the public own a 48.6%, 40.3% and 9.1% interest in us, respectively. Cheniere Holdings' ownership percentage includes its subordinated units and Blackstone CQP Holdco's ownership percentage excludes any common units that may be deemed to be beneficially owned by Blackstone Group, an affiliate of Blackstone CQP Holdco.

NOTE 3—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. As of March 31, 2018 and December 31, 2017, restricted cash consisted of the following (in millions):

	March 31, 2018	December 31, 2017
Current restricted cash		
Liquefaction Project	$ 561	$ 544
CQP and cash held by guarantor subsidiaries	916	1,045
Total current restricted cash	$ 1,477	$ 1,589

Under our $2.8 billion credit facilities (the "2016 CQP Credit Facilities"), we, as well as Cheniere Investments, SPLNG and CTPL as our guarantor subsidiaries, are subject to limitations on the use of cash under the terms of the 2016 CQP Credit Facilities and the related depositary agreement governing the extension of credit to us. Specifically, we, Cheniere Investments, SPLNG and CTPL may only withdraw funds from collateral accounts held at a designated depositary bank on a monthly basis and for specific purposes, including for the payment of operating expenses. In addition, distributions and capital expenditures may only be made quarterly and are subject to certain restrictions.

NOTE 4—ACCOUNTS AND OTHER RECEIVABLES

As of March 31, 2018 and December 31, 2017, accounts and other receivables consisted of the following (in millions):

	March 31, 2018	December 31, 2017
SPL trade receivable	$ 232	$ 185
Other accounts receivable	8	6
Total accounts and other receivables	$ 240	$ 191

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

NOTE 5—INVENTORY

As of March 31, 2018 and December 31, 2017, inventory consisted of the following (in millions):

	March 31, 2018	December 31, 2017
Natural gas	$ 16	$ 17
LNG	14	26
Materials and other	53	52
Total inventory	$ 83	$ 95

NOTE 6—PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2018	December 31, 2017
LNG terminal costs		
LNG terminal	$ 12,690	$ 12,703
LNG terminal construction-in-process	3,431	3,310
Accumulated depreciation	(982)	(880)
Total LNG terminal costs, net	15,139	15,133
Fixed assets		
Fixed assets	23	23
Accumulated depreciation	(17)	(17)
Total fixed assets, net	6	6
Property, plant and equipment, net	$ 15,145	$ 15,139

Depreciation expense was $102 million and $64 million during the three months ended March 31, 2018 and 2017, respectively.

We realized offsets to LNG terminal costs of $124 million in the three months ended March 31, 2017 that were related to the sale of commissioning cargoes because these amounts were earned or loaded prior to the start of commercial operations of the respective Train of the Liquefaction Project, during the testing phase for its construction. We did not realize any offsets to LNG terminal costs in the three months ended March 31, 2018.

NOTE 7—DERIVATIVE INSTRUMENTS

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

- interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under certain credit facilities (“Interest Rate Derivatives”) and
- commodity derivatives consisting of natural gas supply contracts for the commissioning and operation of the Liquefaction Project (“Physical Liquefaction Supply Derivatives”) and associated economic hedges (collectively, the “Liquefaction Supply Derivatives”).

We recognize our derivative instruments as either assets or liabilities and measure those instruments at fair value. None of our derivative instruments are designated as cash flow hedging instruments, and changes in fair value are recorded within our Consolidated Statements of Income to the extent not utilized for the commissioning process.

The following table shows the fair value of our derivative instruments that are required to be measured at fair value on a recurring basis as of March 31, 2018 and December 31, 2017, which are classified as other current assets, non-current derivative assets, derivative liabilities or non-current derivative liabilities in our Consolidated Balance Sheets (in millions).

	Fair Value Measurements as of							
	March 31, 2018				December 31, 2017			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
CQP Interest Rate Derivatives asset	$ —	$ 27	$ —	$ 27	$ —	$ 21	$ —	$ 21
Liquefaction Supply Derivatives asset	—	—	10	10	2	10	43	55

There have been no changes to our evaluation of and accounting for our derivative positions during the three months ended March 31, 2018. See Note 8—Derivative Instruments of our Notes to Consolidated Financial Statements in our annual report on Form 10-K for the year ended December 31, 2017 for additional information.

We value our Interest Rate Derivatives using an income-based approach, utilizing observable inputs to the valuation model including interest rate curves, risk adjusted discount rates, credit spreads and other relevant data. We value our Liquefaction Supply Derivatives using market based approach incorporating present value techniques, as needed, using observable commodity price curves, when available, and other relevant data.

The fair value of our Physical Liquefaction Supply Derivatives is predominantly driven by 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 satisfaction of conditions precedent, including 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 supply contracts.

We include a portion of our Physical Liquefaction Supply Derivatives as Level 3 within the valuation hierarchy as the fair value is developed through the use of internal models which may be impacted by inputs that are unobservable in the marketplace. The curves used to generate the fair value of our Physical 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 Physical 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.

The Level 3 fair value measurements of our Physical Liquefaction Supply Derivatives could be materially impacted by a significant change in certain natural gas market basis spreads due to the contractual notional amount represented by our Level 3 positions, which is a substantial portion of our overall Physical Liquefaction Supply portfolio. The following table includes quantitative information for the unobservable inputs for our Level 3 Physical Liquefaction Supply Derivatives as of March 31, 2018:

	Net Fair Value Asset (in millions)	Valuation Approach	Significant Unobservable Input	Significant Unobservable Inputs Range
Physical Liquefaction Supply Derivatives	$10	Market approach incorporating present value techniques	Basis Spread	$(0.515) - $0.095

The following table shows the changes in the fair value of our Level 3 Physical Liquefaction Supply Derivatives during the three months ended March 31, 2018 and 2017 (in millions):

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Balance, beginning of period	$ 43	$ 79
Realized and mark-to-market losses:		
Included in cost of sales	(13)	(41)
Purchases and settlements:		
Purchases	3	4
Settlements	(23)	(1)
Balance, end of period	$ 10	$ 41
Change in unrealized gains relating to instruments still held at end of period	$ (13)	$ (41)

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, or the risk that a counterparty will be unable to meet its commitments in instances when our derivative instruments are in an asset position. Additionally, we evaluate our own ability to meet our commitments in instances where our derivative instruments are in a liability position. Our derivative instruments are subject to contractual provisions which provide for the unconditional right of set-off for all derivative assets and liabilities with a given counterparty in the event of default.

Interest Rate Derivatives

During the three months ended March 31, 2018, there were no changes to the terms of the interest rate swaps("CQP Interest Rate Derivatives") we entered into to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the 2016 CQP Credit Facilities. See Note 8—Derivative Instruments of our Notes to Consolidated Financial Statements in our annual report on Form 10-K for the year ended December 31, 2017 for additional information.

SPL had entered into interest rate swaps("SPL Interest Rate Derivatives") to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the credit facilities it entered into in June 2015 (the "2015 SPL Credit Facilities"). In March 2017, SPL settled the SPL Interest Rate Derivatives and recognized a derivative loss of $7 million in conjunction with the termination of approximately $1.6 billion of commitments under the 2015 SPL Credit Facilities.

As of March 31, 2018, we 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
CQP Interest Rate Derivatives	$225 million	$1.3 billion	March 22, 2016	February 29, 2020	1.19%	One-month LIBOR

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

Balance Sheet Location	March 31, 2018	December 31, 2017
Other current assets	$ 12	$ 7
Non-current derivative assets	15	14
Total derivative assets	$ 27	$ 21

The following table shows the changes in the fair value and settlements of our Interest Rate Derivatives recorded in derivative gain, net on our Consolidated Statements of Income during the three months ended March 31, 2018 and 2017 (in millions):

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
CQP Interest Rate Derivatives gain	$ 8	$ 2
SPL Interest Rate Derivatives loss	—	(2)

Liquefaction Supply Derivatives

SPL had secured up to approximately 2,179 TBtu and 2,214 TBtu of natural gas feedstock through natural gas supply contracts as of March 31, 2018 and December 31, 2017, respectively. The notional natural gas position of our Liquefaction Supply Derivatives was approximately 1,521 TBtu and 1,520 TBtu as of March 31, 2018 and December 31, 2017, respectively.

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

Balance Sheet Location	Fair Value Measurements as of (1) March 31, 2018	December 31, 2017
Other current assets	$ 8	$ 41
Non-current derivative assets	9	17
Total derivative assets	17	58
Derivative liabilities	(4)	—
Non-current derivative liabilities	(3)	(3)
Total derivative liabilities	(7)	(3)
Derivative asset, net	$ 10	$ 55

(1) Does not include a collateral call of $1 million for such contracts, which is included in other current assets in our Consolidated Balance Sheets as of both March 31, 2018 and December 31, 2017.

The following table shows the changes in the fair value, settlements and location of our Liquefaction Supply Derivatives recorded on our Consolidated Statements of Income during the three months ended March 31, 2018 and 2017 (in millions):

	Statement of Income Location (1)	Three Months Ended March 31, 2018	2017
Liquefaction Supply Derivatives loss (2)	Cost of sales	$ 50	$ 39

(1) Fair value fluctuations associated with commodity derivative activities are classified and presented consistently with the item economically hedged and the nature and intent of the derivative instrument.

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

Balance Sheet Presentation

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

Offsetting Derivative Assets (Liabilities)	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
As of March 31, 2018			
CQP Interest Rate Derivatives	$ 27	$ —	$ 27
Liquefaction Supply Derivatives	25	(8)	17
Liquefaction Supply Derivatives	(9)	2	(7)
As of December 31, 2017			
CQP Interest Rate Derivatives	$ 21	$ —	$ 21
Liquefaction Supply Derivatives	64	(6)	58
Liquefaction Supply Derivatives	(3)	—	(3)

NOTE 8—OTHER NON-CURRENT ASSETS

As of March 31, 2018 and December 31, 2017, other non-current assets, net consisted of the following (in millions):

	March 31, 2018	December 31, 2017
Advances made under EPC and non-EPC contracts	$ 18	$ 26
Advances made to municipalities for water system enhancements	93	93
Advances and other asset conveyances to third parties to support LNG terminals	29	30
Tax-related payments and receivables	25	25
Information technology service assets	23	24
Other	9	8
Total other non-current assets, net	$ 197	$ 206

NOTE 9—ACCRUED LIABILITIES

As of March 31, 2018 and December 31, 2017, accrued liabilities consisted of the following (in millions):

	March 31, 2018	December 31, 2017
Interest costs and related debt fees	$ 186	$ 253
Sabine Pass LNG terminal and related pipeline costs	319	384
Other accrued liabilities	4	—
Total accrued liabilities	$ 509	$ 637

NOTE 10—DEBT

As of March 31, 2018 and December 31, 2017, our debt consisted of the following (in millions):

	March 31, 2018	December 31, 2017
Long-term debt:		
SPL		
5.625% Senior Secured Notes due 2021 (“2021 SPL Senior Notes”), net of unamortized premium of $5 and $6	$ 2,005	$ 2,006
6.25% Senior Secured Notes due 2022 (“2022 SPL Senior Notes”)	1,000	1,000
5.625% Senior Secured Notes due 2023 (“2023 SPL Senior Notes”), net of unamortized premium of $5 and $5	1,505	1,505
5.75% Senior Secured Notes due 2024 (“2024 SPL Senior Notes”)	2,000	2,000
5.625% Senior Secured Notes due 2025 (“2025 SPL Senior Notes”)	2,000	2,000
5.875% Senior Secured Notes due 2026 (“2026 SPL Senior Notes”)	1,500	1,500
5.00% Senior Secured Notes due 2027 (“2027 SPL Senior Notes”)	1,500	1,500
4.200% Senior Secured Notes due 2028 (“2028 SPL Senior Notes”), net of unamortized discount of $1 and $1	1,349	1,349
5.00% Senior Secured Notes due 2037 (“2037 SPL Senior Notes”)	800	800
Cheniere Partners		
5.250% Senior Notes due 2025 (“2025 CQP Senior Notes”)	1,500	1,500
2016 CQP Credit Facilities	1,090	1,090
Unamortized debt issuance costs	(197)	(204)
Total long-term debt, net	16,052	16,046
Current debt:		
$1.2 billion SPL Working Capital Facility (“SPL Working Capital Facility”)	—	—
Total debt, net	$ 16,052	$ 16,046

Credit Facilities

Below is a summary of our credit facilities outstanding as of March 31, 2018 (in millions):

	SPL Working Capital Facility	2016 CQP Credit Facilities
Original facility size	$ 1,200	$ 2,800
Less:		
Outstanding balance	—	1,090
Commitments prepaid or terminated	—	1,470
Letters of credit issued	706	20
Available commitment	$ 494	$ 220
Interest rate	LIBOR plus 1.75% or base rate plus 0.75%	LIBOR plus 2.25% or base rate plus 1.25% (1)
Maturity date	December 31, 2020, with various terms for underlying loans	February 25, 2020, with principal payments due quarterly commencing on March 31, 2019

(1) There is a 0.50% step-up for both LIBOR and base rate loans beginning on February 25, 2019.

Restrictive Debt Covenants

As of March 31, 2018, we and SPL were in compliance with all covenants related to our respective debt agreements.

Interest Expense

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Total interest cost	$ 232	$ 211
Capitalized interest	(47)	(81)
Total interest expense, net	$ 185	$ 130

Fair Value Disclosures

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

	March 31, 2018		December 31, 2017	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Senior notes, net of premium or discount (1)	$ 14,359	$ 15,116	$ 14,360	$ 15,485
2037 SPL Senior Notes (2)	800	838	800	871
Credit facilities (3)	1,090	1,090	1,090	1,090

(1) Includes 2021 SPL Senior Notes, 2022 SPL Senior Notes, 2023 SPL Senior Notes, 2024 SPL Senior Notes, 2025 SPL Senior Notes, 2026 SPL Senior Notes, 2027 SPL Senior Notes, 2028 SPL Senior Notes and 2025 CQP Senior Notes. The Level 2 estimated fair value was based on quotes obtained from broker-dealers or market makers of these senior notes and other similar instruments.

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

(3) Includes SPL Working Capital Facility and 2016 CQP Credit Facilities. The Level 3 estimated fair value approximates the principal amount because the interest rates are variable and reflective of market rates and the debt may be repaid, in full or in part, at any time without penalty.

NOTE 11—REVENUES FROM CONTRACTS WITH CUSTOMERS

The following table represents a disaggregation of revenue earned from contracts with customers during the three months ended March 31, 2018 and 2017 (in millions):

	Three Months Ended March 31,	
	2018	2017
LNG revenues	$ 996	$ 485
LNG revenues—affiliate	503	331
Regasification revenues	65	65
Other revenues	10	2
Other revenues—affiliate	—	1
Total revenues from customers	1,574	884
Revenues from derivative instruments	19	7
Total revenues	$ 1,593	$ 891

LNG Revenues

We have entered into numerous SPAs with third party customers for the sale of LNG on a Free on Board ("FOB") (delivered to the customer at the Sabine Pass LNG terminal) basis. Our customers generally purchase LNG for a price consisting of a fixed fee per MMBtu of LNG (a portion of which is subject to annual adjustment for inflation) plus a variable fee per MMBtu of LNG equal to approximately 115% of Henry Hub. The fixed fee component is the amount payable to us regardless of a cancellation or suspension of LNG cargo deliveries by the customers. The variable fee component is the amount generally payable to us only upon delivery of LNG plus all future adjustments to the fixed fee for inflation. The SPAs and contracted volumes to be made available under the SPAs are not tied to a specific Train; however, the term of each SPA generally commences upon the date of first commercial delivery of a specified Train.

Revenues from the sale of LNG are recognized at a point in time when the LNG is delivered to the customer, at the Sabine Pass LNG terminal, which is the point legal title, physical possession and the risks and rewards of ownership transfers to the customer. Each individual molecule of LNG is viewed as a separate performance obligation. The stated contract price (including both fixed and variable fees) per MMBtu in each LNG sales arrangement is representative of the stand-alone selling price for LNG at the time the sale was negotiated. We have concluded that the variable fees meet the optional exception for allocating variable consideration. As such, the variable consideration for these contracts is allocated to each distinct molecule of LNG and recognized when that distinct molecule of LNG is delivered to the customer. Because of the use of the optional exception, variable consideration related to the sale of LNG is also not included in the transaction price.

Fees received pursuant to SPAs are recognized as LNG revenues only after substantial completion of the respective Train. Prior to substantial completion, sales generated during the commissioning phase are offset against the cost of construction for the respective Train, as the production and removal of LNG from storage is necessary to test the facility and bring the asset to the condition necessary for its intended use.

Regasification Revenues

The Sabine Pass LNG terminal has operational regasification capacity of approximately 4.0 Bcf/d. Approximately 2.0 Bcf/d of the regasification capacity at the Sabine Pass LNG terminal has been reserved under two long-term TUAs with unaffiliated third-party customers, under which they are required to pay fixed monthly fees regardless of their use of the LNG terminal. Each of the customers has reserved approximately 1.0 Bcf/d of regasification capacity. The customers are each obligated to make monthly capacity payments to SPLNG aggregating approximately $125 million annually for 20 years that commenced in 2009, which is representative of fixed consideration in the contract. A portion of this fee is adjusted annually for inflation which is considered variable consideration. The remaining capacity of the Sabine Pass LNG terminal has been reserved by SPL, for which the associated revenues are eliminated in consolidation.

Because SPLNG is continuously available to provide regasification service on a daily basis with the same pattern of transfer, we have concluded that SPLNG provides a single performance obligation to its customers on a continuous basis over time. We have determined that an output method of recognition based on elapsed time best reflects the benefits of this service to the customer and accordingly, LNG regasification capacity reservation fees are recognized as regasification revenues on a straight-line basis over the term of the respective TUAs. We have concluded that the inflation element within the contract meets the optional exception for allocating variable consideration and accordingly the inflation adjustment is not included in the transaction price and will be recognized over the year in which the inflation adjustment relates on a straight-line basis.

In 2012, SPL entered into a partial TUA assignment agreement with Total Gas & Power North America, Inc.("Total"), whereby SPL would progressively gain access to Total's capacity and other services provided under its TUA with SPLNG. This agreement provides SPL with additional berthing and storage capacity at the Sabine Pass LNG terminal that may be used to provide increased flexibility in managing LNG cargo loading and unloading activity, permit SPL to more flexibly manage its LNG storage capacity and accommodate the development of Trains 5 and 6.

Upon substantial completion of Train 3, SPL gained access to a portion ofTotal's capacity and other services provided under Total's TUA with SPLNG. Upon substantial completion of Train 5, SPL will gain access to substantially all of Total's capacity. Notwithstanding any arrangements between Total and SPL, payments required to be made by Total to SPLNG will continue to be made byTotal to SPLNG in accordance with its TUA and we continue to recognize the payments received fromTotal as revenue. During the three months ended March 31, 2018 and 2017, SPL recorded$8 million and zero as operating and maintenance expense under this partial TUA assignment agreement.

Deferred Revenue Reconciliation

The following table reflects the changes in our contract liabilities, which we classify as "Deferred revenue" (in millions):

	Three Months Ended March 31,	
	2018	2017
Deferred revenues, beginning of period	$ 111	$ 73
Cash received but not yet recognized	95	61
Revenue recognized from prior period deferral	(111)	(71)
Deferred revenues, end of period	$ 95	$ 63

We record deferred revenue when we receive consideration, or such consideration is unconditionally due from a customer, prior to transferring goods or services to the customer under the terms of a sales contract. Changes in deferred revenue during the three months ended March 31, 2018 and 2017 are primarily attributable to differences between the timing of revenue recognition and the receipt of advance payments related to delivery of LNG under certain SPAs.

Transaction Price Allocated to Future Performance Obligations

Because many of our sales contracts have long-term durations, we are contractually entitled to significant future consideration which we have not yet recognized as revenue. The following table discloses the aggregate amount of the transaction price that is allocated to performance obligations that have not yet been satisfied as of March 31, 2018:

	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)
LNG revenues	$ 55.2	10.0
Regasification revenues	2.8	5.6
Total revenues	$ 58.0	

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

We have elected the following optional exemptions which omit certain potential future sources of revenue from the table above:

(1) We omit from the table above all performance obligations that are part of a contract that has an original expected duration of one year or less.

(2) We omit from the table above all variable consideration that is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a single performance

obligation when that performance obligation qualifies as a series. The table above excludes all variable consideration under our SPAs and TUAs. The amount of revenue from variable fees that is not included in the transaction price will vary based on the future prices of Henry Hub throughout the contract terms, to the extent customers elect to take delivery of their LNG, and adjustments to the consumer price index. Certain of our contracts contain additional variable consideration based on the outcome of contingent events and the movement of various indexes. The receipt of such variable consideration is considered constrained due to the uncertainty of ultimate pricing and receipt and we have not included such variable consideration in the transaction price. During the three months ended March 31, 2018, approximately 56% of our LNG Revenues, 100% of our LNG revenues—affiliate and approximately 3% of our Regasification Revenues were related to variable consideration received from customers.

We have entered into contracts to sell LNG that are conditioned upon one or both of the parties achieving certain milestones such as reaching a final investment decision on a certain liquefaction Train or obtaining financing. These contracts are considered completed contracts for revenue recognition purposes and are included in the transaction price above.

We have elected the practical expedient to omit the disclosure of the transaction price allocated to future performance obligations and an explanation of when the entity expects to recognize the amount as revenue as of March 31, 2017.

NOTE 12—RELATED PARTY TRANSACTIONS

Below is a summary of our related party transactions as reported on our ConsolidatedStatements of Income for the three months ended March 31, 2018 and 2017 (in millions):

	Three Months Ended March 31,	
	2018	2017
LNG revenues—affiliate		
Cheniere Marketing SPA and Cheniere Marketing Master SPA	$ 503	$ 331
Other revenues—affiliate		
Terminal Marine Services Agreement	—	1
Operating and maintenance expense—affiliate		
Services Agreements	26	18
General and administrative expense—affiliate		
Services Agreements	18	22

LNG Terminal Capacity Agreements

Terminal Use Agreements

SPL obtained approximately 2.0 Bcf/d of regasification capacity and other liquefaction support services under a TUA with SPLNG as a result of an assignment in July 2012 by Cheniere Investments of its rights, title and interest under its TUA with SPLNG. SPL is obligated to make monthly capacity payments to SPLNG aggregating approximately $250 million per year (the “TUA Fees”), continuing until at least 20 years after May 2016.

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

Cheniere 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 pay the TUA Fees required by the TUA to SPLNG. However, the revenue earned by SPLNG from the TUA Fees and the loss incurred by Cheniere Investments under the TURA are eliminated upon consolidation of our Consolidated 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. Cheniere Investments recorded no revenues—affiliate from Cheniere Marketing during the three months ended March 31, 2018 and 2017, respectively, related to the Amended and Restated VCRA.

Cheniere Marketing SPA

Cheniere Marketing has 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.

Cheniere Marketing Master SPA

SPL has an agreement with Cheniere Marketing that allows the parties to sell and purchase LNG with each other by executing and delivering confirmations under this agreement.

Commissioning Confirmation

Under the Cheniere Marketing Master SPA, SPL executed a confirmation with Cheniere Marketing that obligates Cheniere Marketing in certain circumstances to buy LNG cargoes produced during the period while Bechtel Oil, Gas and Chemicals, Inc. has control of, and is commissioning, Train 5 of the Liquefaction Project.

Services Agreements

As of March 31, 2018 and December 31, 2017, we had $97 million and $36 million of advances to affiliates, respectively, under the services agreements described below. The non-reimbursement amounts incurred under the services agreements described below are recorded in general and administrative expense—affiliate.

Cheniere Partners Services Agreement

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

Cheniere Investments Information Technology Services Agreement

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

SPLNG O&M Agreement

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

SPLNG MSA

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

SPL O&M Agreement

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

SPL MSA

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

CTPL O&M Agreement

CTPL has an amended long-term operation and maintenance agreement (the “CTPL O&M Agreement”) with Cheniere Investments pursuant to which CTPL receives all necessary services required to operate and maintain the Creole Trail Pipeline. CTPL is required to reimburse 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.

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

SPLNG has executed CEAs with various Cameron Parish, Louisiana taxing authorities that allowed them to collect certain annual property tax payments from SPLNG from 2007 through 2016. This ten-year initiative represented an aggregate commitment of $25 million in order to aid in their reconstruction efforts following Hurricane Rita, which SPLNG fulfilled in the first quarter of 2016. 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. Beginning in September 2007, SPLNG entered into various agreements with Cheniere Marketing, pursuant to which Cheniere Marketing would pay SPLNG additional TUA revenues equal to any and all amounts payable by SPLNG to the Cameron Parish taxing authorities under the CEAs. In exchange for such amounts received as TUA revenues from Cheniere Marketing, SPLNG will make payments to Cheniere Marketing equal to, and in the year the Cameron Parish dollar-for-dollar credit is applied against, ad valorem tax levied on our LNG terminal.

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 both March 31, 2018 and December 31, 2017, we had $25 million 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.

Terminal Marine Services Agreement

In connection with its tug boat lease, Tug Services entered into an 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.

LNG Terminal Export Agreement

SPLNG and Cheniere Marketing have an LNG Terminal Export Agreement that provides Cheniere Marketing the ability to export LNG from the Sabine Pass LNG terminal. SPLNG did not record any revenues associated with this agreement during the three months ended March 31, 2018 and 2017.

State Tax Sharing Agreements

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

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

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

NOTE 13—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 Statement of Partners' Equity. On April 27, 2018, we declared a $0.55 distribution per common unit and subordinated unit and the related distribution to our general partner and IDR holders to be paid on May 15, 2018 to unitholders of record as of May 7, 2018 for the period from January 1, 2018 to March 31, 2018.

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. Distributions are treated as distributed earnings in the computation of earnings per common unit even though cash distributions are not necessarily derived from current or prior period earnings.

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

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

	Total	Limited Partner Units			General Partner Units	IDR
		Common Units	Class B Units	Subordinated Units		
Three Months Ended March 31, 2018						
Net income	$ 335					
Declared distributions	278	192	—	74	6	6
Assumed allocation of undistributed net income (1)	$ 57	40	—	16	1	—
Assumed allocation of net income		$ 232	$ —	$ 90	$ 7	$ 6
Weighted average units outstanding		348.6	—	135.4		
Net income per unit (2)		$ 0.67		$ 0.67		
Three Months Ended March 31, 2017						
Net income	$ 47					
Declared distributions	25	24	—	—	1	—
Amortization of beneficial conversion feature of Class B units	—	(70)	235	(165)	—	—
Assumed allocation of undistributed net income	$ 22	—	—	22	—	—
Assumed allocation of net income		$ (46)	$ 235	$ (143)	$ 1	$ —
Weighted average units outstanding		57.1	145.3	135.4		
Net loss per unit (2)		$ (0.80)		$ (1.06)		

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

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

NOTE 14—CUSTOMER CONCENTRATION

The following table shows customers with revenues of 10% or greater of total third-party revenues and customers with accounts receivable balances of 10% or greater of total accounts receivable from third parties:

	Percentage of Total Third-Party Revenues		Percentage of Accounts Receivable from Third Parties	
	Three Months Ended March 31,		March 31,	December 31,
	2018	2017	2018	2017
Customer A	31%	54%	33%	39%
Customer B	25%	29%	19%	32%
Customer C	25%	—%	19%	26%
Customer D	*	—%	26%	—%

* Less than 10%

NOTE 15—SUPPLEMENTAL CASH FLOW INFORMATION

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

	Three Months Ended March 31,	
	2018	2017
Cash paid during the period for interest, net of amounts capitalized	$ 242	$ 175

The balance in property, plant and equipment, net funded with accounts payable and accrued liabilities (including affiliate) was $200 million and $316 million as of March 31, 2018 and 2017, respectively.

NOTE 16—RECENT ACCOUNTING STANDARDS

The following table provides a brief description of a recent accounting standard that had not been adopted by us as of March 31, 2018:

Standard	Description	Expected Date of Adoption	Effect on our Consolidated Financial Statements or Other Significant Matters
ASU 2016-02, *Leases (Topic 842)*, and subsequent amendments thereto	This standard requires a lessee to recognize leases on its balance sheet by recording a lease liability representing the obligation to make future lease payments and a right-of-use asset representing the right to use the underlying asset for the lease term. A lessee is permitted to make an election not to recognize lease assets and liabilities for leases with a term of 12 months or less. The standard also modifies the definition of a lease and requires expanded disclosures. This guidance may be early adopted, and must be adopted using a modified retrospective approach with certain available practical expedients.	January 1, 2019	We continue to evaluate the effect of this standard on our Consolidated Financial Statements. This evaluation process includes reviewing all forms of leases, performing a completeness assessment over the lease population, analyzing the practical expedients and assessing opportunities to make certain changes to our lease accounting information technology system in order to determine the best implementation strategy. Preliminarily, we anticipate a material impact from the requirement to recognize all leases upon our Consolidated Balance Sheets. Because this assessment is preliminary and the accounting for leases is subject to significant judgment, this conclusion could change as we finalize our assessment. We have not yet determined the impact of the adoption of this standard upon our results of operations or cash flows. We expect to elect the package of practical expedients permitted under the transition guidance which, among other things, allows the carryforward of prior conclusions related to lease identification and classification. We also expect to elect the practical expedient to retain our existing accounting for land easements which were not previously accounted for as leases. We have not yet determined whether we will elect any other practical expedients upon transition.

Additionally, the following table provides a brief description of recent accounting standards that were adopted by us during the reporting period:

Standard	Description	Date of Adoption	Effect on our Consolidated Financial Statements or Other Significant Matters
ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, and subsequent amendments thereto	This standard provides a single, comprehensive revenue recognition model which replaces and supersedes most 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. The standard requires that the costs to obtain and fulfill contracts with customers should be recognized as assets and amortized to match the pattern of transfer of goods or services to the customer if expected to be recoverable. The standard also requires enhanced disclosures. This guidance may be adopted either retrospectively to each prior reporting period presented subject to allowable practical expedients (“full retrospective approach”) or as a cumulative-effect adjustment as of the date of adoption (“modified retrospective approach”).	January 1, 2018	We adopted this guidance on January 1, 2018, using the full retrospective method. The adoption of this guidance represents a change in accounting principle that will provide financial statement readers with enhanced disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The adoption of this guidance did not impact our previously reported financial statements in any prior period nor did it result in a cumulative effect adjustment to retained earnings. See Note 11—Revenues from Contracts with Customers for additional disclosures.
ASU 2016-16, *Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory*	This standard requires the immediate recognition of the tax consequences of intercompany asset transfers other than inventory. This guidance may be early adopted, but only at the beginning of an annual period, and must be adopted using a modified retrospective approach.	January 1, 2018	The adoption of this guidance did not have an impact on our Consolidated Financial Statements or related disclosures.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Information Regarding Forward-Looking Statements

This quarterly report contains certain statements that are, or may be deemed to be, "forward-looking statements." All statements, other than statements of historical or present facts or conditions, included herein or incorporated herein by reference are "forward-looking statements." Included among "forward-looking statements" are, among other things:

- statements regarding our ability to pay distributions to our unitholders;
- statements regarding our expected receipt of cash distributions from SPLNG, SPL or CTPL;
- statements that we expect to commence or complete construction of our proposed LNG terminals, liquefaction facilities, pipeline facilities or other projects, or any expansions or portions thereof, by certain dates, or at all;
- statements regarding future levels of domestic and international natural gas production, supply or consumption or future levels of LNG imports into or exports from North America and other countries worldwide or purchases of natural gas, regardless of the source of such information, or the transportation or other infrastructure or demand for and prices related to natural gas, LNG or other hydrocarbon products;
- statements regarding any financing transactions or arrangements, or our ability to enter into such transactions;
- statements relating to the construction of our Trains, including statements concerning the engagement of any EPC contractor or other contractor and the anticipated terms and provisions of any agreement with any such EPC or other contractor, and anticipated costs related thereto;
- statements regarding any SPA or other agreement to be entered into or performed substantially in the future, including any revenues anticipated to be received and the anticipated timing thereof, and statements regarding the amounts of total LNG regasification, natural gas liquefaction or storage capacities that are, or may become, subject to contracts;
- statements regarding our planned development and construction of additional Trains, including the financing of such Trains;
- statements that our Trains, when completed, will have certain characteristics, including amounts of liquefaction capacities;
- statements regarding our business strategy, our strengths, our business and operation plans or any other plans, forecasts, projections, or objectives, including anticipated revenues, capital expenditures, maintenance and operating costs and cash flows, any or all of which are subject to change;
- statements regarding legislative, governmental, regulatory, administrative or other public body actions, approvals, requirements, permits, applications, filings, investigations, proceedings or decisions; and
- any other statements that relate to non-historical or future information.

All of these types of statements, other than statements of historical or present facts or conditions, are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology. The forward-looking statements contained in this quarterly 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 quarterly report are not guarantees of future performance and that such statements may not be realized or the forward-looking statements or events may not occur. Actual results may differ materially from those anticipated or implied in forward-looking statements as a result of a variety of factors described in this quarterly report and in the other reports and other information that we file with the SEC, including those discussed under "Risk Factors" in our annual report on Form 10-K for the year ended December 31, 2017 All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. These forward-looking statements speak only as of the date made, and other than as required by law, we undertake no obligation to update or revise any forward-looking statement or provide reasons why actual results may differ, whether as a result of new information, future events or otherwise.

Introduction

The following discussion and analysis presents management's view of our business, financial condition and overall performance and should be read in conjunction with our Consolidated Financial Statements and the accompanying notes. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future. Our discussion and analysis includes the following subjects:

- Overview of Business
- Overview of Significant Events
- Liquidity and Capital Resources
- 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. Our vision is to provide clean, secure and affordable energy to the world, while responsibly delivering a reliable, competitive and integrated source of LNG, in a safe and rewarding work environment. 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 economically justify the use of LNG. Through our wholly owned subsidiary, SPL, we are developing, constructing and operating natural gas liquefaction facilities (the "Liquefaction Project") at the Sabine Pass LNG terminal located in Cameron Parish, Louisiana, on the Sabine-Neches Waterway less than four miles from the Gulf Coast. We plan to construct up to six Trains, which are in various stages of development, construction and operations. Trains 1 through 4 are operational, Train 5 is under construction and Train 6 is being commercialized and has all necessary regulatory approvals in place. Each Train is expected to have a nominal production capacity, which is prior to adjusting for planned maintenance, production reliability and potential overdesign, of approximately 4.5 mtpa of LNG and an adjusted nominal production capacity of approximately 4.3 to 4.6 mtpa of LNG. Through our wholly owned subsidiary, SPLNG, we own and operate regasification facilities at the Sabine Pass LNG terminal, which includes pre-existing infrastructure of five LNG storage tanks with aggregate capacity of approximately 16.9 Bcfe, two marine berths that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. 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, 2018 and through the filing date of this Form 10-Q include the following:

Operational

- As of April 30, approximately 90 cargoes have been produced, loaded and exported from the Liquefaction Project in 2018. To date, approximately 350 cumulative LNG cargoes have been exported from the Liquefaction Project, with deliveries to 26 countries and regions worldwide.

Financial

- In March 2018, the date of first commercial delivery was reached under the 20-year SPA with GAIL (India) Limited relating to Train 4 of the Liquefaction Project.

Liquidity and Capital Resources

The following table provides a summary of our liquidity position at March 31, 2018 and December 31, 2017 (in millions):

	March 31, 2018	December 31, 2017
Cash and cash equivalents	$ —	$ —
Restricted cash designated for the following purposes:		
Liquefaction Project	561	544
CQP and cash held by guarantor subsidiaries	916	1,045
Available commitments under the following credit facilities:		
$1.2 billion SPL Working Capital Facility ("SPL Working Capital Facility")	494	470
2016 CQP Credit Facilities ("2016 CQP Credit Facilities")	220	220

For additional information regarding our debt agreements, see Note 10—Debt of our Notes to Consolidated Financial Statements in this quarterly report and Note 11—Debt of our Notes to Consolidated Financial Statements in our annual report on Form 10-K for the year ended December 31, 2017.

2025 CQP Senior Notes

In September 2017, we issued an aggregate principal amount of $1.5 billion of 5.250% Senior Notes due 2025 ("the 2025 CQP Senior Notes"), which are jointly and severally guaranteed by each of our subsidiaries other than SPL and, subject to certain conditions governing the release of its guarantee, Sabine Pass LNG-LP, LLC (collectively, the "CQP Guarantors"). Net proceeds of the offering of approximately $1.5 billion, after deducting the initial purchasers' commissions and estimated fees and expenses, were used to prepay a portion of the outstanding indebtedness under the 2016 CQP Credit Facilities.

The 2025 CQP Senior Notes are governed by an indenture (the "CQP Indenture"), which contains customary terms and events of default and certain covenants that, among other things, limit our ability and the ability of the CQP Guarantors to incur liens and sell assets, enter into transactions with affiliates, enter into sale-leaseback transactions and consolidate, merge or sell, lease or otherwise dispose of all or substantially all of the applicable entity's properties or assets.

At any time prior to October 1, 2020, we may redeem all or a part of the 2025 CQP Senior Notes at a redemption price equal to 100% of the aggregate principal amount of the 2025 CQP Senior Notes redeemed, plus the "applicable premium" set forth in the CQP Indenture, plus accrued and unpaid interest, if any, to the date of redemption. In addition, at any time prior to October 1, 2020, we may redeem up to 35% of the aggregate principal amount of the 2025 CQP Senior Notes with an amount of cash not greater than the net cash proceeds from certain equity offerings at a redemption price equal to 105.250% of the aggregate principal amount of the 2025 CQP Senior Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption. We also may at any time on or after October 1, 2020 through the maturity date of October 1, 2025, redeem the 2025 CQP Senior Notes, in whole or in part, at the redemption prices set forth in the CQP Indenture.

The 2025 CQP Senior Notes are our senior obligations, ranking equally in right of payment with our other existing and future unsubordinated debt and senior to any of our future subordinated debt. The 2025 CQP Senior Notes will be secured alongside the 2016 CQP Credit Facilities on a first-priority basis (subject to permitted encumbrances) with liens on (1) substantially all the existing and future tangible and intangible assets and our rights and the rights of the CQP Guarantors and equity interests in the CQP Guarantors (except, in each case, for certain excluded properties set forth in the 2016 CQP Credit Facilities) and (2) substantially all of the real property of SPLNG (except for excluded properties referenced in the 2016 CQP Credit Facilities). The liens securing the 2025 CQP Senior Notes would be released if (1) the aggregate principal amount of all indebtedness then outstanding under the term loans under the 2016 CQP Credit Facilities secured by such liens does not exceed $1.0 billion and (2) the aggregate amount of our secured indebtedness and the secured indebtedness of the CQP Guarantors (other than the 2025 CQP Senior Notes or any other series of notes issued under the CQP Indenture) outstanding at any one time, together with all Attributable Indebtedness (as defined in the CQP Indenture) from sale-leaseback transactions (subject to certain exceptions), does not exceed the greater of (1) $1.5 billion and (2) 10% of net tangible assets. Upon the release of the liens securing the 2025 CQP Senior Notes, the limitation on liens covenant under the CQP Indenture will continue to govern the incurrence of liens by us and the CQP Guarantors.

2016 CQP Credit Facilities

In February 2016, we entered into the 2016 CQP Credit Facilities. The 2016 CQP Credit Facilities consist of: (1) a $450 million CTPL tranche term loan that was used to prepay the $400 million term loan facility (the "CTPL Term Loan") in February 2016, (2) an approximately $2.1 billion SPLNG tranche term loan that was used to repay and redeem in November 2016 the approximately $2.1 billion of the senior notes previously issued by SPLNG, (3) a $125 million facility that may be used to satisfy a six-month debt service reserve requirement and (4) a $115 million revolving credit facility that may be used for general business purposes. In September 2017, we issued the 2025 CQP Senior Notes and the net proceeds were used to prepay $1.5 billion of the outstanding indebtedness under the 2016 CQP Credit Facilities. As of both March 31, 2018 and December 31, 2017, we had $220 million of available commitments, $20 million aggregate amount of issued letters of credit and $1.1 billion of outstanding borrowings under the 2016 CQP Credit Facilities.

The 2016 CQP Credit Facilities mature on February 25, 2020, with principal payments due quarterly commencing on March 31, 2019. The outstanding balance may be repaid, in whole or in part, at any time without premium or penalty, except for interest hedging and interest rate breakage costs. The 2016 CQP Credit Facilities contain conditions precedent for extensions of credit, as well as customary affirmative and negative covenants and limit our ability to make restricted payments, including distributions, to once per fiscal quarter as long as certain conditions are satisfied. Under the terms of the 2016 CQP Credit Facilities, we are required to hedge not less than 50% of the variable interest rate exposure on its projected aggregate outstanding balance, maintain a minimum debt service coverage ratio of at least 1.15x at the end of each fiscal quarter beginning March 31, 2019 and have a projected debt service coverage ratio of 1.55x in order to incur additional indebtedness to refinance a portion of the existing obligations.

The 2016 CQP Credit Facilities are unconditionally guaranteed by each of our subsidiaries other than (1) SPL and (2) certain of our subsidiaries owning other development projects, as well as certain other specified subsidiaries and members of the foregoing entities.

Sabine Pass LNG Terminal

Liquefaction Facilities

We are developing, constructing and operating the Liquefaction Project 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 have achieved substantial completion of Trains 1, 2, 3 and 4 of the Liquefaction Project and commenced operating activities in May 2016, September 2016, March 2017 and October 2017, respectively. The following table summarizes the status of Train 5 of the Liquefaction Project as of March 31, 2018:

	Train 5
Overall project completion percentage	89.3%
Completion percentage of:	
Engineering	100%
Procurement	100%
Subcontract work	70.2%
Construction	78.0%
Date of expected substantial completion	1H 2019

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

- Trains 1 through 4—FTA countries for a 30-year term, which commenced on May 15, 2016, and non-FTA countries for a 20-year term, which commenced on June 3, 2016, in an amount up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr of natural gas).
- Trains 1 through 4—FTA countries for a 25-year term and non-FTA countries for a 20-year term in an amount up to a combined total of the equivalent of approximately 203 Bcf/yr of natural gas (approximately 4 mtpa).
- Trains 5 and 6—FTA countries and non-FTA countries for a 20-year term, in an amount up to a combined total of 503.3 Bcf/yr of natural gas (approximately 10 mtpa).

In each case, the terms of these authorizations begin on the earlier of the date of first export thereunder or the date specified in the particular order, which ranges from five to 10 years from the date the order was issued. In addition, SPL received an order providing for a three-year makeup period with respect to each of the non-FTA orders for LNG volumes SPL was authorized but unable to export during any portion of the initial 20-year export period of such order.

In January 2018, the DOE issued orders authorizing SPL to export domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing January 2018, in an aggregate amount up to the equivalent of 600 Bcf of natural gas (however, exports under this order, when combined with exports under the orders above, may not exceed 1,509 Bcf/yr).

Customers

SPL has entered into six fixed price SPAs with terms of at least 20 years (plus extension rights) with third parties to make available an aggregate amount of LNG that is between approximately 80% to 95% of the expected aggregate adjusted nominal production capacity of Trains 1 through 5. Under these SPAs, the customers will purchase LNG from SPL for a price consisting of a fixed fee per MMBtu of LNG (a portion of which is subject to annual adjustment for inflation) plus a variable fee per MMBtu of LNG equal to approximately 115% of Henry Hub. 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 as a result of such cancellation or suspension. We refer to the fee component that is applicable regardless of a cancellation or suspension of LNG cargo deliveries under the SPAs as the fixed fee component of the price under SPL's SPAs. We refer to the fee component that is applicable only in connection with LNG cargo deliveries as the variable fee component of the price under SPL's SPAs. The variable fees under SPL's SPAs were sized at the time of entry into each SPA with the intent to cover the costs of gas purchases and transportation related to, and operating and maintenance costs to produce, the LNG to be sold under each such SPA. The SPAs and contracted volumes to be made available under the SPAs are not tied to a specific Train; however, the term of each SPA generally commences upon the date of first commercial delivery of a specified Train. Under SPL's SPA with BG Gulf Coast LNG, LLC ("BG"), BG has contracted for volumes related to Trains 3 and 4 for which the obligation to make LNG available to BG is expected to commence approximately one year after the date of first commercial delivery for the respective Train.

In aggregate, the annual fixed fee portion to be paid by the third-party SPA customers is approximately $1.6 billion for Trains 1 through 3, increasing to $2.3 billion upon the date of first commercial delivery of Train 4 and to $2.9 billion upon the date of first commercial delivery of Train 5, with the applicable fixed fees starting from the date of first commercial delivery from the applicable Train, as specified in each SPA.

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, Storage and Supply

To ensure SPL is able to transport adequate natural gas feedstock to the Sabine Pass LNG terminal, it has entered into transportation precedent and other agreements to secure firm pipeline transportation capacity with CTPL and third-party pipeline companies. SPL has entered into firm storage services agreements with third parties to assist in managing volatility in natural gas needs for the Liquefaction Project. SPL has also entered into enabling agreements and long-term natural gas supply contracts with third parties in order to secure natural gas feedstock for the Liquefaction Project. As of March 31, 2018, SPL has secured up to approximately 2,179 TBtu of natural gas feedstock through long-term and short-term natural gas supply contracts.

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 of the Liquefaction Project, 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 price of the EPC contract for Train 5 of the Liquefaction Project is approximately $3.1 billion reflecting amounts incurred under change orders through March 31, 2018. 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 $17.5 billion and $18.5 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 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 Train 6.

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 May 2016. SPL entered into a partial TUA assignment agreement with Total, whereby upon substantial completion of Train 3, SPL gained access to a portion of Total's capacity and other services provided under Total's TUA with SPLNG. This agreement provides SPL with additional berthing and storage capacity at the Sabine Pass LNG terminal that may be used to provide increased flexibility in managing LNG cargo loading and unloading activity, permit SPL to more flexibly manage its LNG storage capacity and accommodate the development of Trains 5 and 6. Notwithstanding any arrangements between Total and SPL, payments required to be made by Total to SPLNG will continue to be made by Total to SPLNG in accordance with its TUA. During the three months ended March 31, 2018 and 2017, SPL recorded $8 million and zero, respectively, as operating and maintenance expense under this partial TUA assignment agreement.

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

Capital Resources

We currently expect that SPL's capital resources requirements with respect to Trains 1 through 5 of the Liquefaction Project will be financed through project debt and borrowings and cash flows under the SPAs. We believe that with the net proceeds of borrowings, available commitments under the SPL Working Capital Facility and cash flows from operations, we will have adequate financial resources available to complete Train 5 of the Liquefaction Project and to meet our currently anticipated capital, operating and debt service requirements. SPL began generating cash flows from operations from the Liquefaction Project in May 2016, when Train 1 achieved substantial completion and initiated operating activities. Trains 2, 3 and 4 subsequently achieved substantial completion in September 2016, March 2017 and October 2017, respectively. We realized offsets to LNG terminal costs of $124 million in the three months ended March 31, 2017 that were related to the sale of commissioning cargoes because these amounts were earned or loaded prior to the start of commercial operations, during the testing phase for the construction of those Trains of the Liquefaction Project. We did not realize any offsets to LNG terminal costs in the three months ended March 31, 2018. Additionally, SPLNG generates cash flows from the TUAs, as discussed above.

The following table provides a summary of our capital resources from borrowings and available commitments for the Sabine Pass LNG Terminal, excluding equity contributions to our subsidiaries and cash flows from operations (as described in *Sources and Uses of Cash*), at March 31, 2018 and December 31, 2017 (in millions):

	March 31, 2018	December 31, 2017
Senior notes (1)	$ 15,150	$ 15,150
Credit facilities outstanding balance (2)	1,090	1,090
Letters of credit issued (3)	706	730
Available commitments under credit facilities (3)	494	470
Total capital resources from borrowings and available commitments	$ 17,440	$ 17,440

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

(2) Includes SPL Working Capital Facility and CTPL and SPLNG tranche term loans outstanding under the 2016 CQP Credit Facilities.

(3) Consists of SPL Working Capital Facility. Does not include the letters of credit issued or available commitments under the 2016 CQP Credit Facilities, which are not specifically for the Liquefaction Project.

For additional information regarding our debt agreements related to the Sabine Pass LNG Terminal, see Note 10—Debt of our Notes to Consolidated Financial Statements in this quarterly report and Note 11—Debt of our Notes to Consolidated Financial Statements in our annual report on Form 10-K for the year ended December 31, 2017.

SPL Senior Notes

The SPL Senior Notes are secured on a *pari passu* first-priority basis by a security interest in all of the membership interests in SPL and substantially all of SPL's assets.

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

Both the indenture governing the 2037 SPL Senior Notes (the "2037 SPL Senior Notes Indenture") and the common indenture governing the remainder of the SPL Senior Notes (the "SPL Indenture") include restrictive covenants. SPL may incur additional indebtedness in the future, including by issuing additional notes, and such indebtedness could be at higher interest rates and have different maturity dates and more restrictive covenants than the current outstanding indebtedness of SPL, including the SPL Senior Notes and the SPL Working Capital Facility. Under the 2037 SPL Senior Notes Indenture and the SPL Indenture, SPL may not make any distributions until, among other requirements, deposits are made into debt service reserve accounts as required and a debt service coverage ratio test of 1.25:1.00 is satisfied. Semi-annual principal payments for the 2037 SPL Senior Notes are due on March 15 and September 15 of each year beginning September 15, 2025.

SPL Working Capital Facility

In September 2015, SPL entered into the SPL Working Capital Facility, which is intended to be used for loans to SPL ("Working Capital Loans"), the issuance of letters of credit on behalf of SPL, as well as for swing line loans to SPL ("Swing Line Loans"), primarily for certain working capital requirements related to developing and placing into operation the Liquefaction Project. SPL may, from time to time, request increases in the commitments under the SPL Working Capital Facility of up to $760 million and, 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 March 31, 2018 and December 31, 2017, SPL had $494 million and $470 million of available commitments and $706 million and $730 million aggregate amount of issued letters of credit under the SPL Working Capital Facility, respectively. As of both March 31, 2018 and December 31, 2017, SPL had zero loans outstanding 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. Loans deemed made in connection with a draw upon a letter of credit 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.

Restrictive Debt Covenants

As of March 31, 2018, we and SPL were in compliance with all covenants related to our respective debt agreements.

Sources and Uses of Cash

The following table summarizes the sources and uses of our cash, cash equivalents and restricted cash for the three months ended March 31, 2018 and 2017 (in millions). The table presents capital expenditures on a cash basis; therefore, these amounts differ from the amounts of capital expenditures, including accruals, which are referred to elsewhere in this report. Additional discussion of these items follows the table.

	Three Months Ended March 31,	
	2018	2017
Operating cash flows	$ 331	$ 115
Investing cash flows	(194)	(524)
Financing cash flows	(249)	1,560
Net increase (decrease) in cash, cash equivalents and restricted cash	(112)	1,151
Cash, cash equivalents and restricted cash—beginning of period	1,589	605
Cash, cash equivalents and restricted cash—end of period	$ 1,477	$ 1,756

Operating Cash Flows

Our operating cash inflows during the three months ended March 31, 2018 and 2017 were $331 million and $115 million, respectively. The $216 million increase in operating cash inflows in 2018 compared to 2017 was primarily related to increased cash receipts from the sale of LNG cargoes, partially offset by increased operating costs and expenses as a result of the of additional Trains that were operating at the Liquefaction Project in 2018. There were four Trains operating during the three months ended March 31, 2018, whereas two Trains were operating during the three months ended March 31, 2017.

Investing Cash Flows

Investing cash outflows during the three months ended March 31, 2018 and 2017 were $194 million and $524 million, respectively, and were primarily used to fund the construction costs of the Liquefaction Project. These costs are capitalized as construction-in-process until achievement of substantial completion.

Financing Cash Flows

Financing cash outflows during the three months ended March 31, 2018 were a result of $249 million of distributions to unitholders. Financing cash inflows during the three months ended March 31, 2017 were $1.6 billion, primarily as a result of:

- issuances of SPL's senior notes for an aggregate principal amount of $2.15 billion;
- $55 million of borrowings and $369 million of repayments made under the credit facilities SPL entered into in June 2015;
- $110 million of borrowings and $334 million of repayments made under the SPL Working Capital Facility;
- $26 million of debt issuance costs related to up-front fees paid upon the closing of these transactions; and
- $25 million of distributions to unitholders.

Cash Distributions to Unitholders

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement). Our available cash is our cash on hand at the end of a quarter less the amount of any reserves established by our general partner. All distributions paid to date have been made from accumulated operating surplus. The following provides a summary of distributions paid by us during the three months ended March 31, 2018 and 2017:

				Total Distribution (in millions)			
Date Paid	**Period Covered by Distribution**	**Distribution Per Common Unit**	**Distribution Per Subordinated Unit**	**Common Units**	**Subordinated Units**	**General Partner Units**	**Incentive Distribution Rights**
February 14, 2018	October 1 - December 31, 2017	$ 0.500	$ 0.500	$ 174	$ 68	$ 5	$ 1
February 13, 2017	October 1 - December 31, 2016	0.425	—	24	—	0.5	—

On April 27, 2018, we declared a $0.55 distribution per common unit and subordinated unit and the related distribution to our general partner and incentive distribution right holders to be paid on May 15, 2018 to unitholders of record as of May 7, 2018 for the period from January 1, 2018 to March 31, 2018.

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.

Results of Operations

Our consolidated net income was $335 million, or $0.67 income per common unit (basic and diluted), in the three months ended March 31, 2018, compared to a net income of $47 million, or $0.80 loss per common unit (basic and diluted), in the three months ended March 31, 2017. This $288 million increase in net income in 2018 was primarily a result of increased income from operations due to additional Trains operating between the periods and decreased loss on early extinguishment of debt, which were partially offset by increased interest expense, net of amounts capitalized.

Revenues

	Three Months Ended March 31,		
(in millions, except volumes)	**2018**	**2017**	**Change**
LNG revenues	$ 1,015	$ 492	$ 523
LNG revenues—affiliate	503	331	172
Regasification revenues	65	65	—
Other revenues	10	2	8
Other revenues—affiliate	—	1	(1)
Total revenues	$ 1,593	$ 891	$ 702
LNG volumes recognized as revenues (in TBtu)	241	128	113

We begin recognizing LNG revenues from the Liquefaction Project following the substantial completion and the commencement of operating activities of the respective Trains. During the three months ended March 31, 2018, Trains 1 through 4 were operational, whereas during the three months ended March 31, 2017, only Trains 1 and 2 were operational. Trains 3 and 4 achieved substantial completion in March 2017 and October 2017, respectively. The increase in revenues for the three months ended March 31, 2018 from the comparable period in 2017 was primarily attributable to the increased volume of LNG sold following the achievement of substantial completion of these Trains. We expect our LNG revenues to increase in the future upon Train 5 becoming operational.

Prior to substantial completion of a Train, amounts received from the sale of commissioning cargoes from that Train are offset against LNG terminal construction-in-process because these amounts are earned or loaded during the testing phase for the construction of that Train. We realized offset to LNG terminal costs of $124 million corresponding to 18 TBtu of LNG in the three months ended March 31, 2017 that was related to the sale of commissioning cargoes. There were no commissioning cargoes sold that were realized as offsets to LNG terminal costs in the three months ended March 31, 2018.

Operating costs and expenses

(in millions)	Three Months Ended March 31, 2018	2017	Change
Cost of sales	$ 837	$ 513	$ 324
Operating and maintenance expense	95	50	45
Operating and maintenance expense—affiliate	26	18	8
General and administrative expense	4	3	1
General and administrative expense—affiliate	18	22	(4)
Depreciation and amortization expense	105	66	39
Total operating costs and expenses	$ 1,085	$ 672	$ 413

Our total operating costs and expenses increased during the three months ended March 31, 2018 from the three months ended March 31, 2017, primarily as a result of additional Trains that were operating between the periods. There were four Trains operating during the three months ended March 31, 2018, compared to two Trains operating during the three months ended March 31, 2017.

Cost of sales increased during the three months ended March 31, 2018 from the three months ended March 31, 2017, primarily as a result of the increase in operating Trains during 2018. Cost of sales includes costs incurred directly for the production and delivery of LNG from the Liquefaction Project, to the extent those costs are not utilized for the commissioning process. The increase during the three months ended March 31, 2018 from the three months ended March 31, 2017 was primarily related to the increase in the volume of natural gas feedstock, partially offset by lower prices of natural gas feedstock between the periods. Cost of sales also includes gains and losses from derivatives associated with economic hedges to secure natural gas feedstock for the Liquefaction Project, variable transportation and storage costs and other costs to convert natural gas into LNG.

Operating and maintenance expense (including affiliates) increased during the three months ended March 31, 2018 from the three months ended March 31, 2017, as a result of the increase in operating Trains during 2018. Operating and maintenance expense includes costs associated with operating and maintaining the Liquefaction Project. The increase during the three months ended March 31, 2018 from the three months ended March 31, 2017 was primarily related to natural gas transportation and storage capacity demand charges, third-party service and maintenance contract costs, payroll and benefit costs of operations personnel and TUA reservation charges from payments made under the partial TUA assignment agreement with Total. Operating and maintenance expense (including affiliates) also includes insurance and regulatory costs and other operating costs.

Depreciation and amortization expense increased during the three months ended March 31, 2018 from the three months ended March 31, 2017 as a result of an increased number of operational Trains, as the assets related to the Trains of the Liquefaction Project began depreciating upon reaching substantial completion.

We expect our operating costs and expenses to generally increase in the future upon Train 5 achieving substantial completion, although certain costs will not proportionally increase with the number of operational Trains as cost efficiencies will be realized.

Other expense (income)

(in millions)	Three Months Ended March 31, 2018	2017	Change
Interest expense, net of capitalized interest	$ 185	$ 130	$ 55
Loss on early extinguishment of debt	—	42	(42)
Derivative gain, net	(8)	—	(8)
Other income	(4)	—	(4)
Total other expense	$ 173	$ 172	$ 1

Interest expense, net of capitalized interest, increased during the three months ended March 31, 2018 compared to the three months ended March 31, 2017, primarily as a result of a decrease in the portion of total interest costs that could be capitalized as additional Trains of the Liquefaction Project completed construction between the periods. For the three months ended March 31, 2018, we incurred $232 million of total interest cost, of which we capitalized $47 million, which was directly related to the construction of the Liquefaction Project. For the three months ended March 31, 2017, we incurred $211 million of total interest cost, of which we capitalized $81 million, which was directly related to the construction of the Liquefaction Project.

Loss on early extinguishment of debt decreased during the three months ended March 31, 2018, as compared to the three months ended March 31, 2017. Loss on early extinguishment of debt recognized in 2017 was attributable to the write-off of debt issuance costs upon termination of the remaining available balance of $1.6 billion under SPL's previous credit facilities in connection with the issuance of the 2028 SPL Senior Notes and the 2037 SPL Senior Notes.

Derivative gain, net increased during the three months ended March 31, 2018 compared to the three months ended March 31, 2017, primarily due to a favorable shift in the long-term forward LIBOR curve between the periods. During the three months ended March 31, 2017, the gain attributable to a relative increase in the long-term forward LIBOR curve during the period was partially offset by the $7 million loss recognized upon the termination of interest rate swaps associated with approximately $1.6 billion of commitments that were terminated under SPL's previous credit facilities.

Off-Balance Sheet Arrangements

As of March 31, 2018, 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 our Consolidated Financial Statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and the accompanying notes. There have been no significant changes to our critical accounting estimates from those disclosed in our annual report on Form 10-K for the year ended December 31, 2017.

Recent Accounting Standards

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Marketing and Trading Commodity Price Risk

We have entered into commodity derivatives consisting of natural gas supply contracts 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 commodity price for natural gas for each delivery location as follows (in millions):

	March 31, 2018		December 31, 2017	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
Liquefaction Supply Derivatives	$ 10	$ —	$ 55	$ 5

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 2016 CQP Credit Facilities ("CQP Interest Rate Derivatives"). In order to test the sensitivity of the fair value of the CQP Interest Rate Derivatives to changes in interest rates, management modeled a 10% change in the forward 1-month LIBOR curve across the remaining terms of the CQP Interest Rate Derivatives as follows (in millions):

	March 31, 2018		December 31, 2017	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
CQP Interest Rate Derivatives	$ 27	$ 5	$ 21	$ 5

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

ITEM 4. CONTROLS AND PROCEDURES

We maintain a set of disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports filed by us under the Securities Exchange Act of 1934, as amended (the "Exchange Act") is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. As of the end of the period covered by this report, we evaluated, under the supervision and with the participation of our general partner's management, including our general partner's Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Exchange Act. Based on that evaluation, our general partner's Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective.

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.

PART II. OTHER INFORMATION

ITEM 1. 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. Other than as discussed below, there have been no material changes to the legal proceedings disclosed in our annual report on Form 10-K for the year ended December 31, 2017.

In February 2018, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued a Corrective Action Order (the "CAO") to SPL in connection with a minor LNG leak from one tank and minor vapor release from a second tank at the Sabine Pass LNG terminal. These two tanks have been taken out of operational service while we conduct analysis, repair and remediation. On April 20, 2018, SPL and PHMSA executed a Consent Agreement and Order (the "Consent Order") that replaces and supersedes the CAO. We continue to work with PHMSA and other appropriate regulatory authorities to address the matters identified in the Consent Order. We do not expect that the Consent Order and related analysis, repair and remediation will have a material adverse impact on our financial results or operations.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in our annual report on Form 10-K for the year ended December 31, 2017.

ITEM 6. EXHIBITS

Exhibit No.	Description
10.1*	Change orders 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 SPL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00025 BOG and LNG Rundown, dated January 19, 2018, (ii) the Change Order CO-00026 Design Analysis of Existing East & West Jetty Piping and Structure for Simultaneous Loading, dated February 1, 2018, (iii) the Change Order CO-00027 Performance and Attendance Bonus (PAB) Transfer from Stage 2, dated February 1, 2018, and (iv) the Change Order CO-00028 Existing Jetty Structural Steel Supply, dated February 27, 2018
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.

SIGNATURES

Pursuant to the requirements 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

Date: May 3, 2018 By: /s/ Michael J. Wortley

Michael J. Wortley
Executive Vice President and Chief Financial Officer
(on behalf of the registrant and
as principal financial officer)

Date: May 3, 2018 By: /s/ Leonard Travis

Leonard Travis
Vice President and Chief Accounting Officer
(on behalf of the registrant and
as principal accounting officer)

Exhibit 10.1

CHANGE ORDER FORM
BOG and LNG Rundown

PROJECT NAME: Sabine Pass LNG Stage 3 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00025

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: January 19, 2018

CONTRACTOR: Bechtel Oil, Gas and Chemicals, Inc.

DATE OF AGREEMENT: May 4, 2015

The Agreement between the Parties listed above is changed as follows: *(attach additional documentation if necessary)*

1. Per Article 6.1.B of the Agreement, the Parties agree Contractor will perform the Procurement and Construction services for the BOG and LNG Rundown tie-ins. These services will be based on the Engineering for the BOG and LNG Rundown that was included in the original RFS (RFS 109265 Revision 5).

2. The BOG and LNG Rundown line tie-in packages will be developed after the HAZOP and Model review occurs. These packages will include IFC drawings to procure and construct the required materials. Potential changes due to HAZOP or Model review action items are excluded from this Change Order. For clarity, the tie-ins are depicted in Exhibit A of this Change Order.

3. This Change Order is not included as part of Stage 3 Substantial Completion and will not prevent achievement thereof.

4. The cost breakdown for this Change Order is detailed in Exhibit B.

5. Schedule C-1 (Milestone Payment Schedule) of Attachment C of the Agreement will be amended by including the milestone(s) listed in Exhibit C of this Change Order.

Adjustment to Contract Price

The original Contract Price was	$	2,987,000,000
Net change by previously authorized Change Orders (#00001-00024)	$	95,972,403
The Contract Price prior to this Change Order was	$	3,082,972,403
The Contract Price will be increased by this Change Order in the amount of	$	506,471
The new Contract Price including this Change Order will be	$	3,083,478,874

Adjustment to dates in Project Schedule
The following dates are modified *(list all dates modified; insert N/A if no dates modified)*: **N/A**

Adjustment to other Changed Criteria *(insert N/A if no changes or impact; attach additional documentation if necessary)* **N/A**

Adjustment to Payment Schedule: **Yes. See Exhibit C.**

Adjustment to Minimum Acceptance Criteria: **N/A**

Adjustment to Performance Guarantees: **N/A**

Adjustment to Design Basis: **N/A**

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

Select either A or B:

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

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

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

/s/ Ed Lehotsky	/s/ Bhupesh Thakkar
Owner	Contractor
Ed Lehotsky	Bhupesh Thakkar
Name	Name
SVP LNG E&C	Senior Project Manager
Title	Title
February 15, 2018	January 19, 2018
Date of Signing	Date of Signing

CHANGE ORDER FORM
Design Analysis of Existing East & West Jetty Piping and Structure for Simultaneous Loading

PROJECT NAME: Sabine Pass LNG Stage 3 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00026

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: February 1, 2018

CONTRACTOR: Bechtel Oil, Gas and Chemicals, Inc.

DATE OF AGREEMENT: May 4, 2015

The Agreement between the Parties listed above is changed as follows: *(attach additional documentation if necessary)*

1. Per Article 6.1.B of the Agreement, the Parties agree Contractor shall perform various transient runs along with CSA/PD&P design analysis of the existing East and West Jetty piping and structure for simultaneous loading. The key items for this analysis are listed as follows:
   a. Validation of Contractor's transient model.
   b. Completion of 8,000 m^3/hr simultaneous loading analysis to the existing East and West Jetty. Results will be reviewed by PD&P Pipe Stress to update load tables and identify pipe supports exceeding the original design loads.
   c. Completion of CSA and PD&P design analysis to support loading lines from the existing LNG tanks to the East and West Jetty. In addition, for the proposed modifications, the associated CSA and PD&P redline markups and IFC drawings will be provided to Owner.
2. Owner may not disclose the Contractor Work Product to any third party, unless Contractor's prior written consent has been obtained (such consent not to be unreasonably withheld or delayed), provided that Contractor's prior written consent is hereby deemed to be given for disclosure to the Parties listed in Exhibit A to the extent such Parties have entered into a confidentiality agreement with Owner no less stringent than this Agreement.
3. Notwithstanding anything to the contrary herein, Contractor shall perform the Work in accordance with the standard of skill and care reasonably to be expected in the international engineering and construction industry for projects of the type, size and complexity of the Work contemplated herein. In the event that any such Work under this Change Order fails to meet that standard of performance, Contractor's sole liability and Owner's sole remedy shall be limited to Contractor reperforming such Work at its own expense; provided that notice of such failure is given by Owner within a reasonable time and no later than twelve (12) months from the completion of the Work in question.
4. The Work to be performed under this Change Order is not a condition to and will not prevent the achievement of Substantial Completion of Subproject 5.
5. The cost breakdown for this Change Order is detailed in Exhibit B.
6. Schedule C-1 (Milestone Payment Schedule) of Attachment C of the Agreement will be amended by including the milestone(s) listed in Exhibit C of this Change Order.

Adjustment to Contract Price

The original Contract Price was	$	2,987,000,000
Net change by previously authorized Change Orders (#00001-00025)	$	96,478,874
The Contract Price prior to this Change Order was	$	3,083,478,874
The Contract Price will be increased by this Change Order in the amount of	$	671,121
The new Contract Price including this Change Order will be	$	3,084,149,995

Adjustment to dates in Project Schedule
The following dates are modified *(list all dates modified; insert N/A if no dates modified)*: **N/A**

Adjustment to other Changed Criteria *(insert N/A if no changes or impact; attach additional documentation if necessary)* **N/A**

Adjustment to Payment Schedule: **Yes. See Exhibit C.**

Adjustment to Minimum Acceptance Criteria: **N/A**

Adjustment to Performance Guarantees: **N/A**

Adjustment to Design Basis: **N/A**

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

Select either A or B:

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

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

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

/s/ Ed Lehotsky	/s/ Bhupesh Thakkar
Owner	Contractor
Ed Lehotsky	Bhupesh Thakkar
Name	Name
SVP LNG E&C	Senior Project Manager
Title	Title
February 15, 2018	February 1, 2018
Date of Signing	Date of Signing

CHANGE ORDER FORM
Performance and Attendance Bonus (PAB) Transfer from Stage 2

PROJECT NAME: Sabine Pass LNG Stage 3 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00027

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: February 1, 2018

CONTRACTOR: Bechtel Oil, Gas and Chemicals, Inc.

DATE OF AGREEMENT: May 4, 2015

The Agreement between the Parties listed above is changed as follows: *(attach additional documentation if necessary)*

1. The value of the Performance and Attendance Bonus (PAB) Incentive Program Provisional Sum incorporated into the Agreement in Change Order CO-00005, dated March 16, 2016, was U.S. $36,900,000. Parties now agree the Stage 2 accrued cost for retention of the PAB incentive will be transferred to Stage 3 and invoiced against the PAB value in the Stage 3 Agreement due to Craft personnel moving to Stage 3 as opposed to being released as part of a reduction of Stage 2 workforce. The amount to be transferred is $8,100,000. The contract price will be increased by $8,100,000.

2. The Provisional Sum breakdown is described as follows:

   a. The previous PAB Incentive Program Provisional Sum in Article 2.6 of Attachment EE of the Agreement was Thirty-Six Million, Nine Hundred Thousand U.S. Dollars (U.S. $36,900,000). This Change Order will increase the PAB Incentive Program Provisional Sum by $8,100,000 and the value will be $45,000,000.

   b. The Parties agree to adjust the Aggregate Provisional Sum specified in Article 7.1A of the Agreement which prior to this Change Order was Three Hundred Sixteen Million, Two Hundred Forty-Six Thousand, Four Hundred Thirty-Seven U.S. Dollars (U.S. $316,246,437). This Change Order will increase the Aggregate Provisional Sum amount by Eight Million, One Hundred Thousand U.S. Dollars (U.S. $8,100,000) and the new Aggregate Provisional Sum value shall be Three Hundred Twenty-Four Million, Three Hundred Forty-Six Thousand, Four Hundred Thirty-Seven U.S. Dollars (U.S. $324,346,437).

3. Schedule C-1 (Milestone Payment Schedule) of Attachment C of the Agreement will be amended by including the milestone(s) listed in Exhibit A of this Change Order.

Adjustment to Contract Price

The original Contract Price was	$	2,987,000,000
Net change by previously authorized Change Orders (#00001-00026)	$	97,149,995
The Contract Price prior to this Change Order was	$	3,084,149,995
The Contract Price will be increased by this Change Order in the amount of	$	8,100,000
The new Contract Price including this Change Order will be	$	3,092,249,995

Adjustment to dates in Project Schedule
The following dates are modified *(list all dates modified; insert N/A if no dates modified)*: **N/A**

Adjustment to other Changed Criteria *(insert N/A if no changes or impact; attach additional documentation if necessary)* **N/A**

Adjustment to Payment Schedule: **Yes. See Exhibit A.**

Adjustment to Minimum Acceptance Criteria: **N/A**

Adjustment to Performance Guarantees: **N/A**

Adjustment to Design Basis: **N/A**

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

Select either A or B:

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

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

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

/s/ Ed Lehotsky	/s/ Bhupesh Thakkar
Owner	Contractor
Ed Lehotsky	Bhupesh Thakkar
Name	Name
SVP LNG E&C	Senior Project Manager
Title	Title
February 15, 2018	February 1, 2018
Date of Signing	Date of Signing

CHANGE ORDER FORM
Existing Jetty Structural Steel Supply

PROJECT NAME: Sabine Pass LNG Stage 3 Liquefaction Facility

CHANGE ORDER NUMBER: CO-00028

OWNER: Sabine Pass Liquefaction, LLC

DATE OF CHANGE ORDER: February 27, 2018

CONTRACTOR: Bechtel Oil, Gas and Chemicals, Inc.

DATE OF AGREEMENT: May 4, 2015

The Agreement between the Parties listed above is changed as follows: *(attach additional documentation if necessary)*

1. Per Article 6.1.B of the Agreement, the Parties agree Contractor will obtain structural steel from CIVES via purchase order to support the modifications of the existing jetty. This will require award of a purchase order referencing the existing Stage 3 CIVES purchase order and will require review by the CSA team prior to delivery of the steel to the Site.

2. The following areas will be revised by CIVES: Area 1R1, Area 2R1, Area 3R1 and Area 22R. For clarity, the revised areas are depicted in Exhibit A of this Change Order.

3. The steel associated with this Change Order will be free issued to Owner. The existing Stage 3 contract terms are not applicable to this work and Contractor's obligation is limited to providing steel of good quality and ensuring the steel is fabricated in accordance with the specification, design drawings and fabrication details.

4. The work pursuant to this Change Order is not a condition to and will not prevent the achievement of Stage 3 Substantial Completion or impact the Stage 3 warranty period.

5. The cost breakdown for this Change Order is detailed in Exhibit B.

6. Schedule C-1 (Milestone Payment Schedule) of Attachment C of the Agreement will be amended by including the milestone(s) listed in Exhibit C of this Change Order.

Adjustment to Contract Price

The original Contract Price was	$	2,987,000,000
Net change by previously authorized Change Orders (#00001-00027)	$	105,249,995
The Contract Price prior to this Change Order was	$	3,092,249,995
The Contract Price will be increased by this Change Order in the amount of	$	34,820
The new Contract Price including this Change Order will be	$	3,092,284,815

Adjustment to dates in Project Schedule
The following dates are modified *(list all dates modified; insert N/A if no dates modified)*: **N/A**

Adjustment to other Changed Criteria *(insert N/A if no changes or impact; attach additional documentation if necessary)* **N/A**

Adjustment to Payment Schedule: **Yes. See Exhibit C.**

Adjustment to Minimum Acceptance Criteria: **N/A**

Adjustment to Performance Guarantees: **N/A**

Adjustment to Design Basis: **N/A**

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

Select either A or B:

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

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

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

/s/ Ed Lehotsky	/s/ Bhupesh Thakkar
Owner	Contractor
Ed Lehotsky	Bhupesh Thakkar
Name	Name
SVP LNG E&C	Senior Project Manager
Title	Title
March 13, 2018	February 27, 2018
Date of Signing	Date of Signing

Exhibit 31.1

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

I, Jack A. Fusco, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: May 3, 2018

/s/ Jack A. Fusco

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

Exhibit 31.2

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

I, Michael J. Wortley, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: May 3, 2018

/s/ Michael J. Wortley
Michael J. Wortley
Chief Financial Officer of
Cheniere Energy Partners GP, LLC, the general partner of
Cheniere Energy Partners, L.P.

Exhibit 32.1

CERTIFICATION BY CHIEF EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report of Cheniere Energy Partners, L.P. (the “Partnership”) on Form 10-Q for the quarter ended March 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Jack A. Fusco, Chief Executive Officer of Cheniere Energy Partners GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to my knowledge, that:

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

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

Date: May 3, 2018

/s/ Jack A. Fusco

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

Exhibit 32.2

**CERTIFICATION BY CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the quarterly report of Cheniere Energy Partners, L.P. (the "Partnership") on Form 10-Q for the quarter ended March 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael J. Wortley, Chief Financial Officer of Cheniere Energy Partners GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to my knowledge, that:

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

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

Date: May 3, 2018

/s/ Michael J. Wortley

Michael J. Wortley
Chief Financial Officer of
Cheniere Energy Partners GP, LLC, the general partner of
Cheniere Energy Partners, L.P.