Teekay Offshore Partners L.P.
Form 20-F
February 28, 2019

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

FORM 20-F

(Mark One)
¨ REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g) OF THE SECURITIES EXCHANGE ACT OF 1934
OR
ý ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
OR
¨ SHELL COMPANY REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Date of event requiring this shell company report
For the transition period from to
Commission file number 1-33198

TEEKAY OFFSHORE PARTNERS L.P.
(Exact name of Registrant as specified in its charter)

Not Applicable
(Translation of Registrant’s Name into English)
Republic of the Marshall Islands
(Jurisdiction of incorporation or organization)
4th Floor, Belvedere Building, 69 Pitts Bay Road, Hamilton, HM 08, Bermuda

Telephone: (441) 298-2530
(Address and telephone number of principal executive offices)
Edith Robinson
4th Floor, Belvedere Building, 69 Pitts Bay Road, Hamilton, HM 08, Bermuda
Telephone: (441) 298-2533
Fax: (441) 292-3931
(Contact information for company contact person)
Securities registered, or to be registered, pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
Common Units	New York Stock Exchange
Series A Preferred Units	New York Stock Exchange
Series B Preferred Units	New York Stock Exchange
Series E Preferred Units	New York Stock Exchange
6.00% Notes due 2019	New York Stock Exchange

Securities registered or to be registered, pursuant to Section 12(g) of the Act.
None
Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.
None

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.
410,314,977 Common Units
6,000,000 Series A Preferred Units
5,000,000 Series B Preferred Units
4,800,000 Series E Preferred Units
Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No ý
If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ¨ No ý
Indicate by check mark if 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 ý No ¨
Indicate by check mark if the registrant (1) has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated Filer ¨ Accelerated Filer ý Non-Accelerated Filer ¨ Emerging growth company ¨

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, 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 ¨

† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP x	International Financial Reporting Standards as issued by the International Accounting Standards Board ¨	Other ¨

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow: Item 17 ¨ Item 18 ¨

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý

TEEKAY OFFSHORE PARTNERS L.P.
INDEX TO REPORT ON FORM 20-F

PART I

This Annual Report should be read in conjunction with the consolidated financial statements and accompanying notes included in this report.

Unless otherwise indicated, references in this Annual Report to “Teekay Offshore,” “we,” “us” and “our” and similar terms refer to Teekay Offshore Partners L.P. and/or one or more of its subsidiaries, except that those terms, when used in this Annual Report in connection with the common or preferred units or publicly issued senior notes described herein, shall mean specifically Teekay Offshore Partners L.P.

In addition to historical information, this Annual Report contains forward-looking statements that involve risks and uncertainties. Such forward-looking statements relate to future events and our operations, objectives, expectations, performance, financial condition and intentions. When used in this Annual Report, the words “expect,” “intend,” “plan,” “believe,” “anticipate,” “estimate” and variations of such words and similar expressions are intended to identify forward-looking statements. Forward-looking statements in this Annual Report include, in particular, statements regarding:

- our distribution policy and our ability to make cash distributions on our units or any increases in quarterly distributions;
- our future growth prospects, business strategy and other plans and objectives for future operations;
- future capital expenditures and availability of capital resources to fund capital expenditures;
- our liquidity needs and meeting our going concern requirements, including our working capital deficit, anticipated funds and sources of financing for liquidity needs and the sufficiency of cash flows, and our estimation that we will have sufficient liquidity for a one-year period;
- our ability to refinance existing debt obligations, to raise additional debt and capital (including long-term debt financing for our shuttle tanker newbuildings), to fund capital expenditures, obtain loans from our sponsors, negotiate extensions or redeployments of existing assets and the sale of partial interests of certain assets;
- our ability to maintain and expand long-term relationships with major crude oil companies, including our ability to service fields until they no longer produce, and the negative impact of low oil prices on the likelihood of certain contract extensions;
- the derivation of a substantial majority of revenue from a limited number of customers;
- our ability to leverage to our advantage the expertise, relationships and reputation of Teekay Corporation (Teekay Corporation and/or any one or more of its affiliates or subsidiaries referred to herein as Teekay Corporation) and Brookfield Business Partners L.P. together with its institutional partners (Brookfield Business Partners L.P. and/or any one or more of its affiliates referred to herein as Brookfield) to pursue long-term growth opportunities;
- any offers of shuttle tankers, floating storage and off-take (or FSO) units, or floating production, storage and offloading (or FPSO) units and related contracts from Teekay Corporation and our accepting such offers;
- the outcome and cost of claims and potential claims against us, including claims and potential claims by COSCO (Nantong) Shipyard (or COSCO) relating to Logitel Offshore Rig II Pte Ltd. and Logitel Offshore Pte. Ltd (or Logitel) and cancellation of Units for Maintenance and Safety (or UMS) newbuildings, by Damen Shipyard Group’s DSR Schiedam Shipyard (or Damen) relating to the Petrojarl I FPSO unit upgrade, by Sembcorp Marine Ltd. (or Sembcorp) Shipyard related to the Randgrid FSO unit conversion and by Royal Dutch Shell Plc (or Shell) associated with the Petrojarl Knarr FPSO unit;
- our continued ability to enter into fixed-rate time charters and FPSO contracts with customers, including the effect of a continuation of lower oil prices to motivate charterers to use existing FPSO units on new projects;
- results of operations and revenues and expenses;
- maintaining a reduced level of vessel operating expenses, including services and spares and crewing costs;
- offshore and tanker market fundamentals, including the balance of supply and demand in the offshore and tanker market and spot tanker charter rates;
- our competitive advantage in the shuttle tanker market;

- the expected lifespan of our vessels;
- the estimated sales price or scrap value of vessels;
- our expectations as to any impairment of our vessels;
- acquisitions from third parties and obtaining offshore projects that we or Teekay Corporation bid on or may be awarded;
- certainty of completion, estimated delivery and completion dates, commencement of charter, intended financing and estimated costs for newbuildings, acquisitions and upgrades;
- expected employment and trading of older shuttle tankers;
- our ability to recover the initial discounted rate for the Petrojarl I FPSO unit five-year charter contract over the final 3.5 years of the contract;
- the expectations as to the chartering of unchartered vessels;

1

- our expectations regarding competition in the markets we serve;
- our entering into joint ventures or partnerships with companies;
- our ability to maximize the use of our vessels, including the re-deployment or disposition of vessels no longer under long-term time charter contracts;
- the duration of dry dockings;
- the future valuation of goodwill;
- our compliance with covenants under our credit facilities;
- timing of settlement of amounts due to and from affiliates;
- the ability of the counterparties for our derivative contracts to fulfill their contractual obligations;
- our hedging activities relating to foreign exchange, interest rate and spot market risks;
- our exposure to foreign currency fluctuations, particularly in Norwegian Krone;
- increasing the efficiency of our business and redeploying vessels as charters expire or terminate;
- the adequacy of our insurance coverage;
- the expected impact of heightened environmental and quality concerns of insurance underwriters, regulators and charterers;
- the expected cost of, and our ability to comply with, governmental regulations and maritime self-regulatory organization standards applicable to our business, including the expected cost to install ballast water treatment systems on our vessels in compliance with the International Marine Organization (or IMO) proposals and the effect of IMO 2020;
- anticipated taxation of our partnership and its subsidiaries and taxation of unitholders and the adequacy of our reserves to cover potential liability for additional taxes;
- our intent to take the position that we are not a passive foreign investment company;
- the potential for the reorganization of our FPSO business to result in a lower cost organization going forward;
- our general and administrative expenses as a public company and expenses under service agreements with other affiliates of Teekay Corporation and for reimbursements of fees and costs of Teekay Offshore GP L.L.C., our general partner; and
- our ability to avoid labor disruptions and attract and retain highly skilled personnel.

Forward-looking statements are necessary estimates reflecting the judgment of senior management, involve known and unknown risks and are based upon a number of assumptions and estimates that are inherently subject to significant uncertainties and contingencies, many of which are beyond our control. Actual results may differ materially from those expressed or implied by such forward-looking statements. Important factors that could cause actual results to differ materially include, but are not limited to, those factors discussed below in Item 3 – Key Information: Risk Factors and other factors detailed from time to time in other reports we file with the U.S. Securities and Exchange Commission (or the SEC).

We do not intend to revise any forward-looking statements in order to reflect any change in our expectations or events or circumstances that may subsequently arise. You should carefully review and consider the various disclosures included in this Annual Report and in our other filings made with the SEC that attempt to advise interested parties of the risks and factors that may affect our business, prospects and results of operations.

Item 1. Identity of Directors, Senior Management and Advisers

Not applicable.

Item 2. Offer Statistics and Expected Timetable

Not applicable.

Item 3. Key Information

Selected Financial Data

Set forth below is selected consolidated financial and other data of Teekay Offshore Partners L.P. and its subsidiaries for the fiscal years 2014 through 2018, which have been derived from our consolidated financial statements.

The following tables should be read together with, and are qualified in their entirety by reference to, (a) Item 5. Operating and Financial Review and Prospects, included herein, and (b) the historical consolidated financial statements and the accompanying notes and the Report of

2

Independent Registered Public Accounting Firm thereon (which are included herein), with respect to the consolidated financial statements as at December 31, 2018 and December 31, 2017 and for each of the fiscal years in the three-year period ended December 31, 2018.

In July 2015, we acquired from Teekay Corporation the Petrojarl Knarr FPSO unit, along with its operations and charter contract. The selected financial data and other financial information herein reflect this unit and the results of operations of the unit, referred to herein as the Dropdown Predecessor, as if we had acquired it when the unit began operations under the ownership of Teekay Corporation. The Petrojarl Knarr FPSO unit began operations on March 9, 2015. For a further description of the Dropdown Predecessor, please refer to our Annual Report on Form 20-F for the year ended December 31, 2016.

Our consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (or GAAP).

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in thousands of U.S. Dollars, except per unit, unit and fleet data)				
Income Statement Data:					
Revenues	1,416,424	1,110,284	1,152,390	1,229,413	1,019,539
Income (loss) from vessel operations (1)	111,737	(116,005)	230,853	283,399	256,218
Net (loss) income	(123,945)	(299,442)	44,475	100,143	17,656
Limited partners' interest:					
Net (loss) income	(147,141)	(339,501)	(12,952)	31,205	(19,380)
Net (loss) income per					
Common unit - basic (2)	(0.36)	(1.45)	(0.25)	0.32	(0.22)
Common unit - diluted (2)	(0.36)	(1.46)	(0.25)	0.32	(0.22)
Cash distributions declared per common unit	0.04	0.24	0.44	2.18	2.15
Balance Sheet Data (at end of year):					
Cash and cash equivalents	225,040	221,934	227,378	258,473	252,138
Restricted cash	8,540	28,360	114,909	60,520	46,760
Vessels and equipment (3)	4,270,622	4,687,494	4,716,933	4,743,619	3,183,465
Investments in equity accounted joint ventures	212,202	169,875	141,819	77,647	54,955
Total assets	5,312,052	5,637,795	5,718,620	5,744,166	3,917,837
Total debt	3,097,742	3,123,728	3,182,894	3,363,874	2,408,596
Total equity	1,459,124	1,473,528	1,138,596	967,848	802,853
Common units outstanding	410,314,977	410,045,210	147,514,113	107,026,979	92,386,383
Preferred units outstanding (4)	15,800,000	11,000,000	23,517,745	21,438,413	6,000,000
Cash Flow Data:					
Net cash flow provided by (used for):					
Operating activities	280,643	305,200	396,473	371,456	160,186
Financing activities	(121,338)	142,947	(93,415)	286,663	89,164
Investing activities	(176,019)	(540,140)	(279,764)	(638,024)	(169,578)
Other Financial Data:					
Net revenues (5)	1,264,616	1,010,840	1,071,640	1,131,407	906,999
EBITDA (6)	466,799	162,618	492,648	475,590	306,050
Adjusted EBITDA (6)	782,521	522,394	570,572	615,775	456,528
Expenditures for vessels and equipment	233,736	533,260	294,581	664,667	172,169
Fleet data:					
Average number of shuttle tankers (7)	30.3	31.7	32.5	33.8	34.7
Average number of FPSO units (7)	8.0	8.0	8.0	7.8	5.2

Average number of conventional tankers [7]	2.0	2.0	2.0	3.9	4.0
Average number of FSO units [7]	6.0	6.8	7.0	6.6	6.0
Average number of towing vessels [7]	9.9	7.9	6.3	4.3	—
Average number of units for maintenance and safety [7]	1.0	1.0	1.0	0.9	—

(1)Income (loss) from vessel operations includes, among other things, the following:

3

	Year Ended December 31,				
	2018	2017	2016	2015	2014
(Write-down) and gain (loss) on sale of vessels	(223,355)	(318,078)	(40,079)	(69,998)	(1,638)

(2) Please read Item 18 - Financial Statements: Note 16 - Total Capital and Net Income Per Common Unit.

(3) Vessels and equipment consists of (a) vessels, at cost less accumulated depreciation and write-downs and (b) advances on newbuilding contracts and conversion costs.

(4) Preferred units outstanding includes the Series A Preferred Units from April 23, 2013 through December 31, 2018, the Series B Preferred Units from April 13, 2015 through December 31, 2018, the Series C Preferred Units from July 1, 2015 through June 29, 2016, the Series C-1 and Series D Preferred Units from June 29, 2016 through September 25, 2017, and the Series E Preferred Units from January 18, 2018 through December 31, 2018.

(5) Net revenues is a non-GAAP financial measure. Consistent with general practice in the shipping industry, we use “net revenues”, defined as revenues less voyage expenses. For additional information about this measure, please read Item 5 - Operating and Financial Review and Prospects - Management’s Discussion and Analysis of Financial Conditions and Results of Operations - Important Financial and Operational Terms and Concepts. Net revenues are also widely used by investors and analysts in the shipping industry for comparing financial performance between companies in the shipping industry to industry averages. Net revenue should not be considered as an alternative to revenue or any other measure of financial performance in accordance with GAAP. Net revenue is adjusted for expenses that we classify as voyage expenses and, therefore, may not be comparable to similarly titled measures of other companies. The following table reconciles net revenues with revenues:

	Year Ended December 31,				
	2018	2017	2016	2015	2014
Revenues	1,416,424	1,110,284	1,152,390	1,229,413	1,019,539
Voyage expenses	(151,808)	(99,444)	(80,750)	(98,006)	(112,540)
Net revenues	1,264,616	1,010,840	1,071,640	1,131,407	906,999

(6) EBITDA and Adjusted EBITDA are non-GAAP measures. EBITDA represents net (loss) income before interest, taxes, depreciation and amortization. Adjusted EBITDA represents EBITDA adjusted to exclude certain items whose timing or amount cannot be reasonably estimated in advance or that are not considered representative of core operating performance. Such adjustments include vessel write-downs, gains or losses on sale of vessels, unrealized gains or losses on derivative instruments, foreign exchange gains or losses, losses on debt repurchases, and certain other income or expenses. Adjusted EBITDA also excludes realized gains or losses on interest rate swaps as management, in assessing performance, views these gains or losses as an element of interest expense and realized gains or losses on derivative instruments resulting from amendments or terminations of the underlying instruments. Adjusted EBITDA is further adjusted to include our proportionate share of Adjusted EBITDA from our equity-accounted joint ventures and to exclude the non-controlling interests' proportionate share of the Adjusted EBITDA from our consolidated joint ventures. These measures are used as supplemental financial measures by management and by external users of our financial statements, such as investors and our controlling unitholder, as discussed below.

- Financial and operating performance. EBITDA and Adjusted EBITDA assist our management and investors by increasing the comparability of our fundamental performance from period to period and against the fundamental performance of other companies in our industry that provide EBITDA or Adjusted EBITDA-based information. This increased comparability is achieved by excluding the potentially disparate effects between periods or companies of interest expense and income, taxes, depreciation and amortization, and, for Adjusted EBITDA, by excluding certain additional items whose timing or amount cannot be reasonably estimated in advance or that are not considered representative of core operating performance. These items are affected by various and possibly changing financing methods, capital structure and historical cost basis which may significantly affect net income between periods. We believe that including EBITDA and Adjusted EBITDA as financial and operating measures benefits investors in (a) selecting between investing in us and other investment alternatives and (b) monitoring our ongoing financial and operational strength and health in assessing whether to continue to hold our common and preferred units.

- Liquidity. EBITDA allows us to assess the ability of assets to generate cash sufficient to service debt, make distributions and undertake capital expenditures. By eliminating the cash flow effect resulting from our existing capitalization and other items such as dry-docking expenditures and changes in non-cash working capital items (which may vary significantly from period to period), EBITDA provides a consistent measure of our ability to generate cash over the long term. Management uses this information as a significant factor in determining (a) our proper capitalization structure (including assessing how much debt to incur and whether changes to the capitalization should be made) and (b) whether to undertake material capital expenditures and how to finance them, all in light of cash distribution commitments to preferred unitholders. The use of EBITDA as a liquidity measure also permits investors to assess our fundamental ability to generate cash sufficient to meet cash needs, including distributions on our preferred units.

EBITDA should not be considered as an alternative to net (loss) income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Adjusted EBITDA should not be considered as an alternative to net (loss) income or any other measure of financial performance presented in accordance with GAAP. EBITDA and Adjusted EBITDA exclude certain items that affect net (loss) income and these measures may vary among other companies. Therefore, EBITDA and Adjusted EBITDA as presented in this Annual Report may not be comparable to similarly titled measures of other companies.

The following table reconciles our historical consolidated EBITDA and Adjusted EBITDA to net (loss) income, and our EBITDA to net operating cash flow.

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in thousands of US Dollars)				
Reconciliation of “EBITDA” and “Adjusted EBITDA” (i) to “Net (loss) income”:					
Net (loss) income	(123,945)	(299,442)	44,475	100,143	17,656
Depreciation and amortization	372,290	309,975	300,011	274,599	198,553
Interest expense, net of interest income	195,797	152,183	139,354	122,205	87,662
Income tax expense (recovery)	22,657	(98)	8,808	(21,357)	2,179
EBITDA	466,799	162,618	492,648	475,590	306,050
Write-down and (gain) loss of sale of vessels	223,355	318,078	40,079	69,998	1,638
Realized and unrealized (gain) loss on derivative instruments	(12,808)	42,853	20,313	73,704	143,703
Equity income (ii)	(39,458)	(14,442)	(17,933)	(7,672)	(10,341)
Foreign currency exchange loss	9,413	14,006	14,805	17,467	16,140
Losses on debt repurchases (iii)	55,479	3,102	—	—	—
Other expense (income) - net	4,602	(14,167)	21,031	(1,091)	(781)
Realized (loss) gain on foreign currency forward contracts	(1,228)	900	(7,153)	(13,799)	(1,912)
Adjusted EBITDA from equity-accounted vessels (ii)	92,637	33,360	30,246	27,320	25,722
Adjusted EBITDA attributable to non-controlling interests (iv)	(16,270)	(23,914)	(23,464)	(25,742)	(23,691)
Adjusted EBITDA (i)	782,521	522,394	570,572	615,775	456,528
Reconciliation of “EBITDA” to “Net operating cash flow”:					
Net operating cash flow	280,643	305,200	396,473	371,456	160,186
Expenditures for dry docking	21,411	17,269	26,342	13,060	36,221
Change in non-cash working capital items related to operating activities	83,227	(33,506)	(74,218)	(25,903)	111,484
Amortization of in-process revenue contracts	35,219	12,745	12,779	12,745	12,744
Current income tax expense	4,051	1,772	3,954	1,650	1,290
(Write down) and gain (loss) on sale of vessels	(223,355)	(318,078)	(40,079)	(69,998)	(1,638)
Equity income, net of dividends received	33,258	2,842	10,727	(171)	(6,462)
Unrealized gain (loss) on derivative instruments	53,419	59,702	44,128	(51,072)	(180,156)
Interest expense, net of interest income	195,797	152,183	139,354	122,205	87,662
Other	(16,871)	(37,511)	(26,812)	101,618	84,719
EBITDA	466,799	162,618	492,648	475,590	306,050

(i) In 2018, we changed our definition of Adjusted EBITDA to more closely align with internal management reporting and metrics used by our controlling unitholder. Adjusted EBITDA no longer excludes revenue associated with the amortization of in-process revenue contracts of $12.7 million in 2017, $12.8 million in 2016, $12.7 million in 2015 and $12.7 million in 2014, and other expenses of $0.3 million in 2017, $6.5 million in 2016, $2.7 million in 2015 and $0.4 million in 2014, and now excludes Adjusted EBITDA attributable to non-controlling interests of $23.9 million in 2017, $23.5 million in 2016, $25.7 million in 2015 and $23.7 million in 2014. Adjusted EBITDA amounts reported in prior years have been recast to conform to the definition adopted in 2018.

(ii) Adjusted EBITDA from equity-accounted vessels, which is a non-GAAP measure, should not be considered as an alternative to equity income or any other measure of financial performance presented in accordance with GAAP. Adjusted EBITDA from equity-accounted vessels excludes certain items that affect equity income and these measures may vary among other companies. Therefore, Adjusted EBITDA from equity-accounted vessels as presented in this Annual Report may not be comparable to similarly titled measures of other companies. We do not have control over the operations, nor do we have any legal claim to the revenue and expenses of our investments in equity accounted for joint ventures. Consequently, the cash flow generated by our investments in equity accounted joint ventures may not be available for use by us in the period that such cash flows are generated. Our proportionate share of Adjusted EBITDA from equity-accounted vessels is summarized in the table below:

	Year Ended December 31,				
	2018	2017	2016	2015	2014
Equity income	39,458	14,442	17,933	7,672	10,341
Depreciation and amortization	30,947	10,719	8,715	8,356	8,086
Interest expense, net of interest income	18,585	7,437	3,541	4,234	3,999
Income tax expense (recovery)	442	103	372	161	(32)
EBITDA	89,432	32,701	30,561	20,423	22,394
Add (subtract) specific items affecting EBITDA:					
Write-down and loss on sale of equipment	—	—	676	290	—
Realized and unrealized loss (gain) on derivative instruments	3,523	70	(805)	6,607	3,328
Foreign currency exchange (gain) loss	(318)	589	(186)	—	—
Adjusted EBITDA from equity-accounted vessels	92,637	33,360	30,246	27,320	25,722

(iii) Losses on debt repurchases of $55.5 million for 2018, relates to the prepayment of our $200.0 million promissory note amended and transferred to Brookfield in September 2017 (or the Brookfield Promissory Note) and the repurchases of $225.2 million of the existing $300.0 million five-year senior unsecured bonds maturing in July 2019, and NOK 914 million of the existing NOK 1,000 million senior unsecured bonds maturing in January 2019. The losses on debt repurchases are comprised of an acceleration of non-cash accretion expense of $31.5 million resulting from the difference between the $200.0 million settlement amount of the Brookfield Promissory Note at its par value and its carrying value of $168.5 million and an associated early termination fee of $12.0 million paid to Brookfield, as well as 2.0% - 2.5% premiums on the repurchase of the bonds and the write-off of capitalized loan costs. The carrying value of the Brookfield Promissory Note was lower than face value due to it being recorded at its relative fair value based on the allocation of net proceeds invested by Brookfield on September 25, 2017.

Losses on debt repurchases of $3.1 million for 2017, relates to the repurchase of NOK 508 million of the remaining NOK 1,220 million senior unsecured bonds that matured in late-2018.

(iv) Adjusted EBITDA attributable to non-controlling interests, which is a non-GAAP measure, should not be considered as an alternative to non-controlling interests in net (loss) income or any other measure of financial performance presented in accordance with GAAP. Adjusted EBITDA attributable to non-controlling interests excludes certain items that affect non-controlling interests in net (loss) income and these measures may vary among other companies. Therefore, Adjusted EBITDA attributable to non-controlling interests as presented in this Annual Report may not be comparable to similarly titled measures of other companies. The proportionate share of Adjusted EBITDA attributable to non-controlling interests is summarized in the table below:

	Year Ended December 31,				
	2018	2017	2016	2015	2014
Net (loss) income attributable to non-controlling interests	(7,161)	3,764	11,858	13,911	10,503
Depreciation and amortization	14,617	13,324	12,327	10,727	13,188
Interest expense, net of interest income	2,064	1,549	1,456	1,383	1,602
EBITDA attributable to non-controlling interests	9,520	18,637	25,641	26,021	25,293
Add (subtract) specific items affecting EBITDA:					
Write-down and (gain) loss on sale of vessels	6,711	5,400	(2,270)	(742)	(2,079)
Realized and unrealized loss on derivative instruments	—	—	53	199	285
Foreign currency exchange loss (gain)	39	(123)	41	264	180
Other, net	—	—	(1)	—	12
Adjusted EBITDA attributable to non-controlling interests	16,270	23,914	23,464	25,742	23,691

(7) Average number of vessels consists of the average number of owned and chartered-in vessels that were in our possession during the period, including the Dropdown Predecessor. For 2018, 2017, 2016, 2015 and 2014 this includes two FPSO units in our equity accounted joint ventures, in which we have 50% ownership interests, at 100%.

Risk Factors

Some of the following risks relate principally to the industry in which we operate and to our business in general. Other risks relate principally to the securities market and to the ownership of our 8.50% bonds due 2023, our 6.00% bonds due 2019 and common and preferred units and our warrants. The occurrence of any of the events described in this section could materially and adversely affect our business, financial condition, operating results and ability to pay interest, principal or distributions on, and the trading price of our notes described above and common and preferred units.

Our cash flow depends substantially on the ability of our subsidiaries to make distributions to us.
The source of our cash flow includes cash distributions from our subsidiaries. The amount of cash our subsidiaries can distribute to us principally depends upon the amount of cash they generate from their operations, which may fluctuate from quarter to quarter based on, among other things:

- the rates they obtain from their FPSO contracts, charters, voyages, management fees and contracts of affreightment (whereby our subsidiaries carry an agreed quantity of cargo for a customer over a specified trade route within a given period of time);
- the rates and the utilization of our towage fleet;
- the price and level of production of, and demand for, crude oil, particularly the level of production at the offshore oil fields our subsidiaries service under contracts of affreightment;
- the operating performance of our FPSO units, whereby receipt of incentive-based revenue from our FPSO units is dependent upon the fulfillment of the applicable performance criteria, including additional compensation from periodic production tariffs, which are based on the volume of oil produced, the price of oil, as well as other monthly or annual operational performance measures;
- the level of their operating costs, such as the cost of crews and repairs and maintenance;
- the number of off-hire days for their vessels and the timing of, and number of days required for, dry docking of vessels;
- the rates, if any, at which our subsidiaries may be able to redeploy shuttle tankers in the spot market as conventional oil tankers during any periods of reduced or terminated oil production at fields serviced by contracts of affreightment;
- the rates, if any, at which our subsidiaries may be able to redeploy vessels, particularly FPSO units, after they complete their charters or contracts and are redelivered to us;
- the ability of our subsidiaries to contract our newbuilding vessels and the rates thereon (if any);
- delays in the delivery of any newbuildings and the beginning of payments under charters relating to those vessels;
- prevailing global and regional economic and political conditions;
- currency exchange rate fluctuations; and
- the effect of governmental regulations and maritime self-regulatory organization standards on the conduct of business.

The actual amount of cash our subsidiaries have available for distribution also depends on other factors such as:

- the level of their capital expenditures, including for maintaining vessels or converting existing vessels for other uses and complying with regulations;
- their debt service requirements and restrictions on distributions contained in their debt agreements;
- fluctuations in their working capital needs;
- their ability to make working capital or long-term borrowings; and
- the amount of any cash reserves, including reserves for future maintenance capital expenditures, working capital and other matters, established by the board of directors of our general partner at its discretion.

The amount of cash our subsidiaries generate from operations may differ materially from their profit or loss for the period, which will be affected by non-cash items and the timing of debt service payments. As a result of this and the other factors mentioned above, our subsidiaries may make cash distributions during periods when they record losses and may not make cash distributions during periods when they record net income.
Our ability to pay distributions on our units, and the amount of distributions that we may pay in the future, largely depends upon the distributions that we receive from our subsidiaries, and we may not have sufficient cash from operations to enable us to pay distributions to our common unitholders.
In January 2019 we announced that we are reducing our quarterly common unit cash distributions to zero, down from $0.01 per common unit in previous quarters, in order to reinvest additional cash in our business and further strengthen our balance sheet. We may not have sufficient available cash from operations each quarter to enable us to resume

payment of a distribution to our common unitholders. The source of our earnings and cash flow includes cash distributions from our subsidiaries. Therefore, the amount of distributions we are able to make to our unitholders will fluctuate based on the level of distributions made to us by our subsidiaries. Our subsidiaries may not make quarterly distributions at a level that will permit us to resume or increase our quarterly distributions in the future. In addition, while we would expect to resume distributions, subject to Brookfield approval, to our common unitholders if our subsidiaries increase distributions to us, the timing of such

resumption and the amount of any such distributions will not necessarily be comparable to the timing and amount of the increase in distributions made by our subsidiaries to us.
Our ability to distribute to our unitholders any cash we may receive from our subsidiaries is or may be limited by a number of factors, including, among others:

- interest expense and principal payments on any indebtedness we incur;
- distributions on any preferred units we have issued or may issue;
- capital expenditures related to committed projects;
- changes in our cash flows from operations;
- restrictions on distributions contained in any of our current or future debt agreements;
- fees and expenses of us, our general partner, its affiliates or third parties we are required to reimburse or pay, including expenses we incur as a result of being a public company; and
- reserves the board of directors of our general partner believes are prudent for us to maintain for the proper conduct of our business or to provide for future distributions, including reserves for future capital expenditures and for anticipated future credit needs.

Many of these factors reduce the amount of cash we may otherwise have available for distribution. The actual amount of cash that is available for distribution to our unitholders depends on several factors, many of which are beyond the control of us or our general partner.
We may issue additional common units or other equity securities in the future. The issuance of additional common units and other equity securities may be dilutive to unitholders and increases the risk that we will not have sufficient available cash to make cash distributions to our unitholders or increase future distribution levels.
Issuing additional equity securities in the future may result in further unitholder dilution and further increase the aggregate amount of cash required to resume quarterly distributions on our common units or increase future distribution levels.
If we resume paying cash distributions on our common units in the future, our ability to grow and to meet our financial needs may be adversely affected by our cash distribution policy.
Although global crude oil and gas prices have experienced moderate recovery since falling from the highs of mid-2014, prices have not returned to those same highs and remain volatile due to global and regional geopolitical, economic and strategic risks and changes. This decline, combined with other factors beyond our control, has adversely affected energy and master limited partnership capital markets and available sources of financing. Based on upcoming capital requirements for our committed growth projects and scheduled debt repayment obligations, coupled with uncertainty regarding how long it will take for the energy and master limited partnership capital markets to normalize, we believe it is in the best interests of our common unitholders to conserve more of our internally generated cash flows to fund these projects and to reduce debt levels. As a result, in September 2017 and in January 2019, we reduced our quarterly distributions on our common units, and our near-to-medium-term business strategy is primarily focused on funding and implementing existing growth projects, extending contracts and redeploying existing assets on long-term charters and repaying or refinancing scheduled debt obligations.

If we resume paying a quarterly cash distribution on our common units, in determining the amount of cash available for distribution, the board of directors of our general partner, in making the determination on our behalf, would approve the amount of cash reserves to set aside, including reserves for future capital expenditures, anticipated future credit needs, working capital and other matters. We would also rely upon external financing sources, including commercial borrowings and proceeds from debt and equity offerings, to fund our capital expenditures. Accordingly, to the extent we do not have sufficient cash reserves or are unable to obtain financing, our cash distribution policy may significantly impair our ability to meet our financial needs or to grow.

Current market conditions limit our access to capital and our growth prospects.

We have relied primarily upon bank financing and debt and equity offerings to fund our growth. Current depressed market conditions in the energy sector and for master limited partnerships have significantly reduced our access to capital, particularly equity capital. Debt financing or refinancing may not be available on acceptable terms, if at all. Issuing significant additional common equity given current market conditions would be highly dilutive and costly. Lack of access to debt or equity capital at reasonable rates will adversely affect our growth prospects and our ability to refinance debt and make distributions to our unitholders.

Our ability to repay or refinance our debt obligations and to fund our capital expenditures and estimated funding gaps will depend on certain financial, business and other factors, many of which are beyond our control. To the extent we are able to finance these obligations and expenditures with cash from operations or by issuing debt or equity securities, our ability to make cash distributions may be diminished, our financial leverage may increase or our unitholders may be diluted. Our business may be adversely affected if we need to access other sources of funding.

To fund our existing and future debt obligations and capital expenditures, we will be required to use cash from operations, incur borrowings including securing debt financing on our under-levered and unmortgaged vessels, enter into sale-leaseback transactions, raise capital through the sale of assets, debt or additional equity securities and/or seek to access other financing sources, including financing or re-financing loans from our sponsors, Brookfield and Teekay Corporation. Our ability to draw on committed funding sources and potential funding sources and our future financial and operating performance will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond our control.

If we are unable to access additional bank financing and generate sufficient cash flow to meet our debt, capital expenditure and other business requirements, we may be forced to take actions such as:

•restructuring our debt;
•seeking additional debt or equity capital;
•selling additional assets or equity interests in certain assets or joint ventures;
•reducing, delaying or cancelling our business activities, acquisitions, investments or capital expenditures; or
•seeking bankruptcy protection.

Such measures might not be successful, and additional debt or equity capital may not be available on acceptable terms or enable us to meet our debt, capital expenditure and other obligations. Some of such measures may adversely affect our business and reputation. In addition, our financing agreements may restrict our ability to implement some of these measures. The sale of certain assets will reduce cash from operations and the cash available for distributions to unitholders.

Use of cash from operations for capital purposes will reduce cash available for distribution to unitholders. Our ability to obtain bank financing or to access the capital markets for future offerings may be limited by our financial condition at the time of any such financing or offering as well as by adverse market conditions in general. Even if we are successful in obtaining necessary funds, the terms of such financings could limit our ability to pay cash distributions to unitholders or operate our business as currently conducted. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional equity securities may result in significant unitholder dilution and would increase the aggregate amount of cash required to resume and make any increase in our quarterly distributions to unitholders.

Primarily as a result of the working capital deficit and committed capital expenditures, over the one-year period following the issuance of our 2018 consolidated financial statements, we will need to obtain additional sources of financing, in addition to amounts generated from operations, to meet our liquidity needs and our minimum liquidity requirements under our financial covenants. Additional potential sources of financing include refinancing debt facilities, increasing amounts available under existing debt facilities and entering into new debt facilities, including long-term debt financing related to the six shuttle tanker newbuildings ordered. We are actively pursuing the funding alternatives described above, which we consider probable of completion based on our history of being able to raise and refinance loan facilities. We are in various stages of completion on these matters.
We have limited current liquidity.
As at December 31, 2018, we had total liquidity of $225.0 million and a working capital deficit of $487.6 million. Our limited availability under existing credit facilities and our current working capital deficit could limit our ability to meet our financial obligations and growth prospects. We expect to manage our working capital deficit primarily with net operating cash flow, including extensions and redeployments of existing assets, debt financing and re-financings, and our existing liquidity. However, there can be no assurance that any such funding will be available to us on acceptable terms, if at all.
We must make substantial capital expenditures to maintain the operating capacity of our fleet, which reduces cash available for distribution. In addition, each quarter our general partner is required to deduct estimated maintenance capital expenditures from operating surplus, which may result in less cash available to unitholders than if actual maintenance capital expenditures were deducted.
We must make substantial capital expenditures to maintain, over the long term, the operating capacity of our fleet. Maintenance capital expenditures include capital expenditures associated with dry docking a vessel, modifying an

existing vessel or acquiring a new vessel to the extent these expenditures are incurred to maintain the operating capacity of our fleet. These expenditures could increase as a result of changes in:

- the cost of labor and materials;
- customer requirements;
- increases in fleet size or the cost of replacement vessels;
- governmental regulations and maritime self-regulatory organization standards relating to safety, security or the environment; and
- competitive standards.

In addition, actual maintenance capital expenditures vary significantly from quarter to quarter based on the number of vessels dry docked during that quarter. Certain repair and maintenance items are more efficient to complete while a vessel is in dry dock. Consequently, maintenance capital expenditures will typically increase in periods when there is an increase in the number of vessels dry docked. Significant maintenance capital expenditures reduce the amount of cash that we have available to make distribution to our unitholders.

Our partnership agreement requires our general partner to deduct our estimated, rather than actual, maintenance capital expenditures from operating surplus each quarter in an effort to reduce fluctuations in operating surplus (as defined in our partnership agreement). The amount of estimated maintenance capital expenditures deducted from operating surplus is subject to review and change by the Conflicts Committee of our general partner at least once a year. In years when estimated maintenance capital expenditures are higher than actual maintenance capital expenditures, the amount of cash available for distribution to unitholders is lower than if actual maintenance capital expenditures were deducted from operating surplus. If our general partner underestimates the appropriate level of estimated maintenance capital expenditures, we may have less cash available for distribution in future periods when actual capital expenditures begin to exceed our previous estimates.
We require substantial capital expenditures and generally are required to make significant installment payments for acquisitions of newbuilding vessels or for the conversion of existing vessels prior to their delivery and generation of revenue.
Currently, the total cost for an Aframax or Suezmax-size shuttle tanker is approximately $85 to $150 million, the cost of an FSO unit is approximately $50 to $250 million, the cost of an FPSO unit is approximately $200 million (for purchasing an older, idle FPSO unit) to over $2 billion for building a new FPSO unit, although actual costs vary significantly depending on the market price charged by shipyards, the size and specifications of the vessel, governmental regulations and maritime self-regulatory organization standards.

We regularly evaluate and pursue opportunities to provide marine transportation services and offshore oil production and storage services for new or expanding offshore projects. Under an omnibus agreement that we entered into in connection with our initial public offering, Teekay Corporation is required to offer to us certain shuttle tankers, FSO units and FPSO units that Teekay Corporation owns or may acquire in the future, provided the vessels are servicing contracts with remaining durations of greater than three years. We may also acquire other vessels that Teekay Corporation may offer us from time to time and pursue direct acquisitions from third parties and new offshore projects. Neither we nor Teekay Corporation may be awarded charters or contracts of affreightment relating to any of the projects we pursue or it pursues, and we may choose not to purchase the vessels Teekay Corporation is required to offer to us under the omnibus agreement. If we elect pursuant to the omnibus agreement to obtain Teekay Corporation’s interests in any projects that Teekay Corporation may be awarded, or if we bid on and are awarded contracts relating to any offshore project, we will need to incur significant capital expenditures to buy Teekay Corporation’s interest in these offshore projects or to build the offshore units.

Although delivery of the completed vessel will not occur until much later (approximately two to three years from the time the order is placed), we typically must pay between 10% to 20% of the purchase price of a shuttle tanker upon signing the purchase contract. During the construction period, we generally are required to make installment payments on newbuildings prior to their delivery, in addition to incurring financing, miscellaneous construction and project management costs. If we finance these acquisition costs by issuing debt or equity securities, we will increase the aggregate amount of interest or cash required to make quarterly distributions to unitholders, if any, prior to generating cash from the operation of the newbuilding.

Our substantial capital expenditures may reduce our cash available for distribution to our unitholders. Funding of any capital expenditures with debt may significantly increase our interest expense and financial leverage, and funding of capital expenditures through issuing additional equity securities may result in significant unitholder dilution. Our failure to obtain the funds for future capital expenditures could have a material adverse effect on our business, results of operations and financial condition and on our ability to make cash distributions.
Our substantial debt levels may limit our flexibility in obtaining additional financing, refinancing credit facilities upon maturity, pursuing other business opportunities and paying distributions.
As at December 31, 2018, our total debt was approximately $3.1 billion and we were fully drawn under our revolving credit facilities. We plan to increase our total debt relating to our shuttle tanker newbuildings and on our under-levered and unmortgaged vessels. If we are awarded contracts for additional offshore projects or otherwise acquire additional

vessels or businesses, our consolidated debt may significantly increase. We may incur additional debt under these or future credit facilities. Our level of debt could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes, and our ability to refinance our credit facilities may be impaired or such financing may not be available on favorable terms;
- limiting management’s discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- we will need a substantial portion of our cash flow from operations to make principal and interest payments on our debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to unitholders;
- our debt level may make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our industry, increases in interest rates or the economy generally;
- if our cash flow and capital resources are insufficient to fund debt service obligations, forcing us to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance our indebtedness; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy the obligations under our indebtedness, which may not be successful.
Given volatility associated with our business and industry, our future cash flow may be insufficient to meet our debt obligations and other commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors, including those beyond our control, will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt obligations. If our cash flows and capital resources are insufficient to fund our debt service obligations and other commitments, we may be forced to reduce or delay planned investments and capital expenditures, or to sell assets, seek additional financing in the debt or equity markets or restructure or refinance our indebtedness, including the notes. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and may be required to dispose of material assets or operations to meet our debt service and other obligations. We may not be able to consummate those dispositions or to obtain the proceeds that we could have realized from them and any proceeds may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our debt service obligations.
Financing agreements containing operating and financial restrictions may restrict our business and financing activities.
The operating and financial restrictions and covenants in our current financing arrangements and any future financing agreements could adversely affect our ability to finance future operations or capital needs or to engage, expand or pursue our business activities. For example, the arrangements may restrict the ability of us and our subsidiaries to:

•incur additional indebtedness or guarantee indebtedness;
•change ownership or structure, including mergers, consolidations, liquidations and dissolutions;
•make dividends or distributions or repurchase or redeem our equity securities;
•prepay, redeem or repurchase certain debt;
•issue certain preferred units or similar equity securities;
•make certain negative pledges and grant certain liens;
•sell, transfer, assign or convey assets;
•enter into transactions with affiliates;
•create unrestricted subsidiaries;
•make certain acquisitions and investments;
•enter into agreements restricting our subsidiaries' ability to pay dividends;
•make loans and certain investments; and
•enter into a new line of business.

One revolving credit facility is guaranteed by us for all outstanding amounts and contains covenants that require us to maintain a minimum liquidity (cash, cash equivalents and undrawn committed revolving credit lines with at least six months to maturity) in an amount equal to the greater of $75.0 million and 5.0% of our total consolidated debt. One revolving credit facility is guaranteed by subsidiaries of ours, and contains covenants that require Teekay Shuttle Tankers L.L.C. (or ShuttleCo) to maintain a minimum liquidity (cash, cash equivalents and undrawn committed revolving credit lines with at least six months to maturity) in an amount equal to the greater of $35.0 million and 5.0% of ShuttleCo's total consolidated debt, a minimum ratio of twelve months' historical EBITDA relative to total interest expense and installments of 1.20x, which can be mitigated by cash deposits, and a net debt to total capitalization ratio no greater than 75.0%. The revolving credit facilities are collateralized by first-priority mortgages granted on 19 of our vessels, together with other related security. The ability of us to comply with covenants and restrictions contained in debt instruments may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, compliance with these covenants may be impaired. If restrictions, covenants, ratios or tests in the financing agreements are breached, a significant portion or all of the obligations may become immediately due and payable, and the lenders' commitment to make further loans may terminate. This could lead to cross-defaults under other financing agreements and result in obligations becoming due and commitments being terminated under such agreements. We might not have, nor be able to obtain, sufficient funds to make these accelerated payments.

Obligations under our credit facilities are secured by certain vessels, and if we are unable to repay debt under the credit facilities, the lenders could seek to foreclose on those assets. We have one revolving credit facility and seven term loans that require us to maintain vessel values to drawn principal balance ratios of a minimum range of 100% to 125%. As at December 31, 2018, these ratios ranged from 122% to 414% and we were in compliance with the minimum ratios required. The vessel values used in calculating these ratios are the appraised values provided by third parties where available, or prepared by us based on second-hand sale and purchase market data. Changes in the shuttle tanker, towage and offshore installation, UMS, or FPSO markets could negatively affect these ratios.

Furthermore, the termination of any of our charter contracts by our customers could result in the repayment of the debt facilities to which the chartered vessels relate.

At December 31, 2018, we were in compliance with all covenants in our credit facilities and other long-term debt agreements.

Restrictions in our financing agreements may prevent us or our subsidiaries from paying distributions.

The payment of principal and interest on our debt reduces cash available for distribution to us and on our units. In addition, our and our subsidiaries' financing agreements prohibit the payment of distributions upon the occurrence of the following events, among others:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to notify the lenders of any material oil spill or discharge of hazardous material, or of any action or claim related thereto;
- breach or lapse of any insurance with respect to vessels securing the facilities;
- breach of certain financial covenants;
- failure to observe any other agreement, security instrument, obligation or covenant beyond specified cure periods in certain cases;
- default under other indebtedness;
- bankruptcy or insolvency events;
- failure of any representation or warranty to be materially correct;
- a change of control, as defined in the applicable agreement; and
- a material adverse effect, as defined in the applicable agreement.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase.

We are exposed to the impact of interest rate changes, primarily through our floating-rate borrowings that require us to make interest payments based on LIBOR or NIBOR. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease. In addition, there is uncertainty as to the continued use of LIBOR in the future. LIBOR is the subject of recent national, international and other regulatory guidance and proposals for reform. These reforms and other pressures may cause LIBOR to be eliminated or to perform differently than in the past. The consequences of these developments cannot be entirely predicted, but could include an increase in the cost of our variable rate indebtedness and obligations.

We derive a substantial majority of our revenues from a limited number of customers, and the loss of any such customers could result in a significant loss of revenues and cash flow.

We have derived, and we believe we will continue to derive, a substantial majority of revenues and cash flow from a limited number of customers. Royal Dutch Shell Plc (or Shell, formerly BG Group Plc), Petroleo Brasileiro S.A. (or Petrobras), Equinor ASA (or Equinor, formerly Statoil ASA) accounted for approximately 23%, 18% and 13%, respectively, of our consolidated revenues during 2018. Shell, Petrobras, Equinor and Premier Oil plc (or Premier Oil, formerly E.ON Ruhgras UK GP Limited or E.ON) accounted for approximately 31%, 17% 10% and 10%, respectively, of our consolidated revenues during 2017. Shell, Petrobras and Premier Oil accounted for approximately 30%, 19% and 10%, respectively, of our consolidated revenues during 2016. No other customer accounted for 10% or more of revenues during any of these periods. Please read Item 18 – Financial Statements: Note 5 – Segment Reporting.

We could lose a customer or the benefits of a contract if:

- the customer fails to make payments because of its financial inability, disagreements with us or otherwise;
- we agree to reduce the payments due to us under a contract because of the customer's inability to continue making the original payments;
- the customer exercises certain rights to terminate the contract; or

- the customer terminates the contract because we fail to deliver the vessel within a fixed period of time, the vessel is lost or damaged beyond repair, there are serious deficiencies in the vessel or prolonged periods of off-hire, or we default under the contract.

If we lose a key customer, we may be unable to obtain replacement long-term charters or contracts of affreightment and may become subject, with respect to any shuttle tankers redeployed on conventional oil tanker trades, to the volatile spot market, which is highly competitive and subject to significant price fluctuations. If a customer exercises its right under some charters to purchase the vessel, or terminate the charter, we may be unable to acquire an adequate replacement vessel or charter. Any replacement newbuilding would not generate revenues during its construction and we may be unable to charter any replacement vessel on terms as favorable to us as those of the terminated charter.

The loss of any of our significant customers or a reduction in revenues from them could have a material adverse effect on our business, results of operations and financial condition and our ability to make cash distributions.

Allegations of improper payments may harm our reputation and business
In May 2016, a former executive of Transpetro, the transportation and logistics subsidiary of Petrobras, alleged in a plea bargain that a subsidiary of ours, among a number of other third-party shipping companies, purportedly made improper payments to obtain shuttle tanker business with Transpetro. Such payments by our subsidiary were alleged to have been made between 2004 and 2006, prior to our initial public offering, in an aggregate amount of approximately 1.5 million Brazilian Reals (less than $0.4 million at the December 31, 2018 exchange rate). We conducted an extensive internal investigation, with the assistance of United States, Brazilian and Norwegian counsel and forensic accountants, to evaluate these allegations. Based on the information reasonably available and reviewed as part of the investigation, the investigation did not identify conclusive proof that we or any of our subsidiaries made the alleged improper payments or that any of our or our subsidiaries' current or former employees intended for the alleged improper payments to be made. However, there is no assurance the conclusions of the investigation are accurate or will not be challenged, or that other information may exist or become available that would affect such conclusions, and such conclusions are not binding on regulatory or governmental authorities. It is uncertain how these allegations ultimately may affect us, if at all, including the possibility of penalties that could be assessed by relevant authorities. Any claims against us may adversely affect our reputation, business, financial condition and operating results. In addition, any dispute with Petrobras in connection with this matter may adversely affect our relationship with Petrobras. As of the date of this Annual Report, no legal or governmental proceedings are pending or, to our knowledge, contemplated against us relating to these allegations.

In January 2015, through the Libra joint venture, OOG-TK Libra GmbH & Co KG (or the Libra Joint Venture), a 50/50 joint venture of the Partnership and Ocyan S.A. (or Ocyan) (formerly Odebrecht Oil & Gas S.A.), we finalized a contract with Petrobras to provide an FPSO unit for the Libra field located in the Santos Basin offshore Brazil. The contract is being serviced by the Pioneiro de Libra (or Libra) FPSO unit, which commenced operations in late-2017 under a 12-year firm period fixed-rate contract with Petrobras and its international partners. Senior Odebrecht S.A. personnel, including a former executive of Ocyan, have been implicated in corruption charges related to improper payments to Brazilian politicians and political parties. Any adverse effect of these charges against Ocyan may harm our growth prospects, reputation, financial condition and results of operations.
We depend on Teekay Corporation and certain joint venture partners to assist us in operating our businesses and competing in our markets.
We have entered into various services agreements with certain direct and indirect subsidiaries of Teekay Corporation pursuant to which those subsidiaries provide to us certain administrative and other services. During 2018, we acquired several of these direct and indirect subsidiaries from Teekay Corporation. Our operational success and ability to execute our growth strategy depends on the performance of these services by the subsidiaries. Our business could be harmed if such subsidiaries fail to perform these services satisfactorily or if they stop providing these services.

In addition, we have entered into, and expect to enter into additional, joint venture arrangements with third parties to expand our fleet and access growth opportunities. In particular, we rely on the expertise and relationships that our joint ventures and joint venture partners may have with current and potential customers to jointly pursue FPSO projects and provide assistance in competing in new markets.

Our ability to compete for offshore oil marine transportation, processing, offshore accommodation, support for maintenance and modification projects, towage and offshore installation and storage projects and to enter into new charters or contracts of affreightment and expand our customer relationships depends on our ability to maintain our status as a reputable service provider in the industry in addition to our ability to leverage our relationship with Brookfield, Teekay Corporation or our joint venture partners and their reputation and relationships in the shipping and offshore industries. If Brookfield, Teekay Corporation or our joint venture partners suffer material damage to their reputation or relationships, it may harm the ability of us or other subsidiaries to:

•renew existing charters and contracts of affreightment upon their expiration;

- obtain new charters and contracts of affreightment;
- successfully interact with shipyards during periods of shipyard construction constraints;
- obtain financing on commercially acceptable terms; or
- maintain satisfactory relationships with suppliers and other third parties.

If our ability to do any of the things described above is impaired, it could have a material adverse effect on our business, results of operations and financial condition and our ability to make cash distributions.

A decline in oil prices may adversely affect our growth prospects and results of operations.

A decline in oil prices may adversely affect our business, results of operations and financial condition and our ability to make cash distributions, as a result of, among other things:

- a reduction in exploration for or development of new offshore oil fields, or the delay or cancellation of existing offshore projects as energy companies lower their capital expenditures budgets, which may reduce our growth opportunities;
- a reduction in, or termination of, production of oil at certain fields we service, which may reduce our revenues under volume-based contracts of affreightment, production-based and oil price-based components of our FPSO unit contracts or life-of-field contracts;

- lower demand for vessels of the types we own and operate, which may reduce available charter rates and revenue to us upon redeployment of our vessels, in particular FPSO units, following expiration or termination of existing contracts or upon the initial chartering of vessels, or which may result in extended periods of our vessels being idle between contracts;
- customers potentially seeking to renegotiate or terminate existing vessel contracts, failing to extend or renew contracts upon expiration, or seeking to negotiate cancelable contracts;
- the inability or refusal of customers to make charter payments to us due to financial constraints or otherwise; or
- declines in vessel values, which may result in losses to us upon vessel sales or impairment charges against our earnings.

Our growth depends on continued growth in demand for offshore oil transportation and processing and storage services.

Our long-term growth strategy focuses on expansion in the shuttle tanker and FPSO sectors. Accordingly, our growth depends on continued growth in world and regional demand for these offshore services, which could be negatively affected by a number of factors, such as:

- decreases in the actual or projected price of oil, which could lead to a reduction in or termination of production of oil at certain fields we service or a reduction in exploration for or development of new offshore oil fields;
- increases in the production of oil in areas linked by pipelines to consuming areas, the extension of existing, or the development of new, pipeline systems in markets we may serve, or the conversion of existing non-oil pipelines to oil pipelines in those markets;
- decreases in the consumption of oil due to increases in its price relative to other energy sources, other factors making consumption of oil less attractive or energy conservation measures;
- availability of new, alternative energy sources; and
- negative global or regional economic or political conditions, particularly in oil consuming regions, which could reduce energy consumption or its growth. Reduced demand for offshore marine transportation, processing, storage services, offshore accommodation or towage and offshore installation services would have a material adverse effect on our future growth and could harm our business, results of operations and financial condition.

Because payments under our contracts of affreightment are based on the volume of oil transported and a portion of the payments under certain of our FPSO contracts are based on the volume of oil produced and the price of oil, utilization of our shuttle tanker fleet, the success of our shuttle tanker business and the revenue from our FPSO units depends upon continued production from existing or new oil fields, which is beyond our control and generally declines naturally over time.

A portion of our shuttle tankers operates under contracts of affreightment. Payments under these contracts of affreightment are based upon the volume of oil transported, which depends upon the level of oil production at the fields we service under the contracts. Payments made to us under certain of our FPSO contracts are partially based on an incentive component, which is determined by the volume of oil produced. Oil production levels are affected by several factors, all of which are beyond our control, including: geologic factors, including general declines in production that occur naturally over time; mechanical failure or operator error; the rate of technical developments in extracting oil and related infrastructure and implementation costs; the availability of necessary drilling and other governmental permits; the availability of qualified personnel and equipment; strikes, employee lockouts or other labor unrest; and regulatory changes. In addition, the volume of oil produced may be adversely affected by extended repairs to oil field installations or suspensions of field operations as a result of oil spills or otherwise.

The rate of oil production at fields we service may decline from existing levels. If such a reduction occurs, the spot market rates in the conventional oil tanker trades at which we may be able to redeploy the affected shuttle tankers may be lower than the rates previously earned by the vessels under the contracts of affreightment. Low spot market rates for the shuttle tankers or any idle time prior to the commencement of a new contract or our inability to redeploy any of our FPSO units at an acceptable rate may have an adverse effect on our business and operating results.

The duration of many of our shuttle tanker, FSO and FPSO contracts is the life of the relevant oil field or is subject to extension by the field operator or vessel charterer. If the oil field no longer produces oil or is abandoned or the contract term is not extended, we will no longer generate revenue under the related contract and will need to seek to redeploy affected vessels.

Some of our shuttle tanker contracts have a “life-of-field” duration, which means that the contract continues until oil production at the field ceases. If production terminates or the field is abandoned for any reason, we no longer will generate revenue under the related contract. Other shuttle tanker, FSO and FPSO contracts under which our vessels operate are subject to extensions beyond their initial term. The likelihood of these contracts being extended may be negatively affected by reductions in oil field reserves, low oil prices generally or other factors. If we are unable to promptly redeploy any affected vessels at rates at least equal to those under the contracts, if at all, our operating results will be harmed. Any potential redeployment may not be under long-term contracts, which may affect the stability of our cash flow and our ability to make cash distributions.

The redeployment risk of FPSO units is high given their lack of alternative uses and significant costs.

FPSO units are specialized vessels that have very limited alternative uses and high fixed costs. In addition, FPSO units typically require substantial capital investments prior to being redeployed to a new field and production service contract. These factors increase the redeployment

risk of FPSO units. Unless extended, one of our FPSO production service contracts will expire in 2019 and a further contract will expire in 2020. Our clients may also terminate certain of our FPSO production service contracts prior to their expiration under specified circumstances. Any idle time prior to the commencement of a new contract or our inability to redeploy the vessels at acceptable rates may have an adverse effect on our business and operating results.
Future adverse economic conditions, including disruptions in the global credit markets, could adversely affect our results of operations.
Commencing in 2007 and 2008, the global economy experienced an economic downturn and crisis in the global financial markets that produced illiquidity in the capital markets, market volatility, and increased exposure to interest rate and credit risks and reduced access to capital markets. Additionally, although global crude oil and gas prices have experienced moderate recovery since falling from the highs of mid-2014, prices have not returned to those same highs and this has adversely affected energy and master limited partnership capital markets and available sources of financing. If there is economic instability in the future, we may face restricted access to the capital markets or secured debt lenders, such as our revolving credit facilities. This decreased access to such resources could have a material adverse effect on our business, financial condition and results of operations.
Future adverse economic conditions or other developments may affect our customers’ ability to charter our vessels and pay for our services and may adversely affect our business and results of operations.
Future adverse economic conditions or other developments relating directly to our customers may lead to a decline in our customers’ operations or ability to pay for our services, which could result in decreased demand for our vessels and services. Our customers’ inability to pay for any reason could also result in their default on our current contracts and charters. The decline in the amount of services requested by our customers or their default on our contracts with them could have a material adverse effect on our business, financial condition and results of operations.
The results of our shuttle tanker and FPSO operations in the North Sea are subject to seasonal fluctuations.
Due to harsh winter weather conditions, oil field operators in the North Sea typically schedule oil platform and other infrastructure repairs and maintenance during the summer months. Because the North Sea is one of our primary existing offshore oil markets, this seasonal repair and maintenance activity contributes to quarter-to-quarter volatility in our results of operations, as oil production typically is lower in the second and third quarters in this region compared with production in the first and fourth quarters. Because a portion of our North Sea shuttle tankers operate under contracts of affreightment, under which revenue is based on the volume of oil transported, the results of these shuttle tanker operations in the North Sea under these contracts generally reflect this seasonal pattern of transport demand. Additionally, our North Sea FPSO units, the Petrojarl Knarr and Voyageur Spirit FPSO units, operate higher in the winter months, as favorable weather conditions in the summer months provide opportunities for repairs and maintenance to our units, which generally reduces oil production. When we redeploy affected shuttle tankers as conventional oil tankers while platform maintenance and repairs are conducted, the overall financial results for the North Sea shuttle tanker operations may be negatively affected as the rates in the conventional oil tanker markets are usually lower than contract of affreightment rates. In addition, we seek to coordinate some of the general dry-docking schedule of our fleet with this seasonality, which may result in lower revenues and increased dry-docking expenses during the summer months.
Our recontracting of existing vessels and our future growth depends on our ability to expand relationships with existing customers and obtain new customers, for which we will face substantial competition.
One of our principal objectives is to enter into additional long-term, fixed-rate time charters and contracts of affreightment, including the redeployment of our assets as their current charter contracts expire. The process of obtaining new long-term time charters and contracts of affreightment is highly competitive and generally involves an intensive screening process and competitive bids, and often extends for several months. Shuttle tanker, FSO, FPSO, towage and offshore installation vessel and UMS contracts are awarded based upon a variety of factors relating to the vessel operator, including:

•industry relationships and reputation for customer service and safety;
•experience and quality of ship operations;
•quality, experience and technical capability of the crew;

- relationships with shipyards and the ability to get suitable berths;
- construction management experience, including the ability to obtain on-time delivery of new vessels or conversions according to customer specifications;
- willingness to accept operational risks pursuant to the charter, such as allowing termination of the charter for force majeure events; and
- competitiveness of the bid in terms of overall price.

We expect competition for providing services for potential offshore projects from other experienced companies, including state-sponsored entities. Our competitors may have greater financial resources than us. This increased competition may cause greater price competition for charters. As a result of these factors, we may be unable to expand our relationships with existing customers or to obtain new customers on a profitable basis, if at all, which would have a material adverse effect on our business, results of operations and financial condition and our ability to make cash distributions to unitholders.

Delays in the operational start-up of FPSO units or deliveries of newbuilding vessels could harm our operating results. The operational start-up of FPSO units, the completion of final performance tests of FPSO units, or the deliveries of any newbuilding vessels we may order or undertake could be delayed, which would delay our receipt of revenues under the charters or other contracts related to the units or vessels. In addition, under some charters we may enter into, if the operational start-up or our delivery of the newbuilding vessel to our customer is delayed, we may be required to pay liquidated damages during the delay. For prolonged delays, the customer may terminate the charter and, in addition to the resulting loss of revenues, we may be responsible for substantial liquidated damages.

The operational start-up of FPSO units or completion and deliveries of newbuildings or of vessel conversions or upgrades could be delayed because of:

- quality or engineering problems, the risk of which may be increased with FPSO units due to their technical complexity;
- changes in governmental regulations or maritime self-regulatory organization standards;
- work stoppages or other labor disturbances at the shipyard;
- bankruptcy or other financial crisis of the shipbuilder;
- a backlog of orders at the shipyard;
- political or economic disturbances;
- weather interference or catastrophic events, such as a major earthquake or fire;
- requests for changes to the original vessel specifications;
- shortages of or delays in the receipt of necessary construction materials, such as steel;
- inability to finance the construction or conversion of the vessels; or
- inability to obtain requisite permits or approvals.

If the operational start-up of an FPSO unit or the delivery of a newbuilding vessel is materially delayed, it could adversely affect our results of operations and financial condition and our ability to make cash distributions to unitholders.

Charter rates for towage and offshore installation vessels may fluctuate substantially over time and may be lower when we are attempting to charter our towage and offshore installation vessels, which could adversely affect operating results. Any changes in charter rates for shuttle tankers, FSO or FPSO units and UMS could also adversely affect redeployment opportunities for those vessels.

Our ability to charter our towage and offshore installation vessels will depend, among other things, on the state of the towage market. Towage contracts are highly competitive and are based on the level of projects undertaken by the customer base. There also exists some volatility in charter rates for shuttle tankers, FSO and FPSO units and UMS, which could affect our ability to charter or recharter these vessels at acceptable rates, if at all.

Over time, the value of our vessels may decline, which could adversely affect our operating results.

Values for shuttle tankers, FSO and FPSO units, towage and offshore installation vessels and UMS can fluctuate substantially over time due to a number of different factors, including:

- prevailing economic conditions in oil and energy markets;
- a substantial or extended decline in demand for oil;
- increases in the supply of vessel capacity;
- competition from more technologically advanced vessels;
- the cost of retrofitting or modifying existing vessels, as a result of technological advances in vessel design or equipment, changes in applicable environmental or other regulations or standards, or otherwise; and
- a decrease in oil reserves in the fields in which our FPSO units or other vessels are or might be deployed.

Vessel values may decline from existing levels. If the operation of a vessel is not profitable, or if we cannot re-deploy a vessel at attractive rates upon termination of its contract, rather than continue to incur costs to maintain and finance the vessel, we may seek to dispose of it. Our inability to dispose of the vessel at a reasonable value could result in a loss on its sale and adversely affect our results of operations and financial condition. Further, if we determine at any time that a vessel's future useful life and earnings require us to impair its value on our financial statements, we may need to recognize a significant charge against our earnings.

We have recognized write-downs on certain vessels and may recognize additional vessel write-downs in the future, which could adversely affect our operating results.

During 2018, we recognized aggregate vessel write-downs of $223.4 million, net of a net gain on sale of vessels, relating to our determination that seven of our vessels were impaired and that their carrying values should be written down to their respective estimated fair values based on a discounted cash flow approach or using appraised values. Please read Item 18 – Financial Statements: Note 18 – (Write-down) and Gain (Loss) on Sale of Vessels and Conventional Tankers Dispositions. The non-cash charges related to these or other impairments or write-downs will reduce our operating results for the applicable period.

Climate change and greenhouse gas restrictions may adversely impact our operations and markets.

Due to concern over the risk of climate change, a number of countries have adopted, or are considering the adoption of, regulatory frameworks to reduce greenhouse gas emissions. These regulatory measures include, among others, adoption of cap and trade regimes, carbon taxes, increased efficiency standards, and incentives or mandates for renewable energy. Compliance with changes in laws, regulations and obligations relating to climate change could increase our costs related to operating and maintaining our vessels and require us to install new emission controls, acquire allowances or pay taxes related to our greenhouse gas emissions, or administer and manage a greenhouse gas emissions program. Revenue generation and strategic growth opportunities may also be adversely affected.

Adverse effects upon the oil industry relating to climate change may also adversely affect demand for our services. Although we do not expect that demand for oil will reduce dramatically over the short term, in the long term, climate change may reduce the demand for oil or increased regulation of greenhouse gases may create greater incentives for use of alternative energy sources. Any long-term material adverse effect on the oil industry could have a significant adverse financial and operational impact on our business that we cannot predict with certainty at this time.

We may be unable to make or realize expected benefits from acquisitions, and implementing our growth strategy through acquisitions may harm our business, financial condition and operating results.

Our long-term growth strategy includes selectively acquiring or constructing shuttle tankers and FPSO units as needed for approved projects only after charters for the projects have been awarded to us, rather than ordering vessels on a speculative basis. Historically, there have been very few purchases of existing vessels and businesses in the FPSO segments. Factors that may contribute to a limited number of acquisition opportunities for FPSO units in the near term include the relatively small number of independent FPSO fleet owners. In addition, competition from other companies, many of which have significantly greater financial resources than do we could reduce our acquisition opportunities or cause us to pay higher prices.

Any acquisition of a vessel or business may not be profitable at or after the time of acquisition and may not generate cash flow sufficient to justify the investment. In addition, our acquisition growth strategy exposes us to risks that may harm our business, financial condition and operating results, including risks that we may:

- fail to realize anticipated benefits, such as new customer relationships, cost-savings or cash flow enhancements;
- be unable to hire, train or retain qualified shore and seafaring personnel to manage and operate our growing business and fleet;
- decrease our liquidity by using a significant portion of available cash or borrowing capacity to finance acquisitions;
- significantly increase our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- incur or assume unanticipated liabilities, losses or costs associated with the business or vessels acquired; or
- incur other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

Unlike newbuilding vessels, existing vessels typically do not carry warranties as to their condition. While we generally inspect existing vessels prior to purchase, such an inspection would normally not provide us with as much knowledge of a vessel's condition as we would possess if it had been built for us and operated by us during its life. Repairs and maintenance costs for existing vessels are difficult to predict and may be substantially higher than for vessels we have operated since they were built. These costs could decrease our cash flow and reduce our liquidity.

We may not be successful in our entry into new markets, which may have competitive dynamics that differ from markets in which we already participate, and we may be unsuccessful in gaining acceptance in these markets from customers or competing against other companies with more experience or larger fleets or resources in these markets. We also may not be successful in employing the Alexita Spirit shuttle tanker, the HiLoad DP unit, the Petrojarl Varg FPSO unit, the Arendal Spirit UMS or the ALP Ace and ALP Forward towage and offshore installation vessels, each of which is currently in lay-up, on contracts sufficient to recover our investment in the vessels.

We may fail to realize the anticipated benefits of the strategic partnership with Brookfield.

We, Brookfield and Teekay Corporation entered into investment agreements (or the Brookfield Transaction) with the expectation that the investment transactions would result in various benefits, including, among other things, the ability to fully finance our existing growth projects, resulting in significant near-term cash flow growth, the ability to better service our customers and take advantage of future growth opportunities. The success of the investment transactions will depend, in part, on our ability to realize such anticipated benefits from the investments. The anticipated benefits of the investment transactions may not be realized fully, or at all, or may take longer to realize than expected. Failure to achieve anticipated benefits could result in increased costs and decreases in the amounts of expected revenues or operating results of us following the closing of the Brookfield Transaction.

Our and many of our customers' substantial operations outside the United States expose us to political, governmental and economic instability, which could harm our operations.
Because our operations are primarily conducted outside of the United States, they may be affected by economic, political and governmental conditions in the countries where we engage in business or where our vessels are registered. Any disruption caused by these factors could harm our business, including by reducing the levels of oil exploration, development and production activities in these areas. We derive some of our revenues from shipping oil from politically unstable regions, in particular, our operations in Brazil and elsewhere in South America. Conflicts in these regions have included attacks on ships and other efforts to disrupt shipping. Hostilities or other political instability in regions where we operate or where we may operate could have a material adverse effect on the growth of our business, results of operations and financial condition and ability to make cash distributions. In addition, tariffs, trade embargoes and other economic sanctions by the United States or other countries against countries in Southeast Asia, the Middle East or elsewhere as a result of terrorist attacks, hostilities or otherwise may limit trading activities with those countries, which could also harm our business and ability to make cash distributions. Finally, governments could requisition one or more of our vessels, which is most likely during war or national emergency. Any such requisition would cause a loss of the vessel and could harm our cash flow and financial results.
Marine transportation and oil production is inherently risky, particularly in the extreme conditions in which many of our vessels operate. An incident involving significant loss of product or environmental contamination by any of our vessels could harm our reputation and business.
Vessels and their cargoes, and oil production facilities we service, are at risk of being damaged or lost because of events such as:

•marine disasters;
•adverse weather;
•mechanical failures;
•grounding, capsizing, fire, explosions and collisions;
•piracy;
•cyber attacks;
•human error; and
•war and terrorism.

A portion of our shuttle tanker fleet and our towage fleet, two FSO units, and the Voyageur Spirit and Petrojarl Knarr FPSO units operate in the North Sea. Harsh weather conditions in this region and other regions in which our vessels operate may increase the risk of collisions, oil spills, or mechanical failures.

An accident involving any of our vessels could result in any of the following:

•death or injury to persons, loss of property or damage to the environment and natural resources;
•delays in the delivery of cargo;
•loss of revenues from charters or contracts of affreightment;
•liabilities or costs to recover any spilled oil or other petroleum products and to restore the eco-system affected by the spill;
•governmental fines, penalties or restrictions on conducting business;
•higher insurance rates; and
•damage to our reputation and customer relationships generally.

Any of these results could have a material adverse effect on our business, financial condition and operating results. In addition, any damage to, or environmental contamination involving, oil production facilities serviced could suspend that service and result in loss of revenues.

Our insurance may not be sufficient to cover losses that may occur to our property or as a result of our operations.
The operation of shuttle tankers, conventional oil tankers, FSO and FPSO units, towage and offshore installation vessels, and UMS, is inherently risky. All risks may not be adequately insured against, and any particular claim may not be paid by insurance. In addition, all but three of our vessels, the Petrojarl Knarr FPSO unit, the Itajai FPSO unit and the Libra FPSO unit, are not insured against loss of revenues resulting from vessel off-hire time, based on the cost of this insurance compared to our off-hire experience. Any significant off-hire time of our vessels could harm our business, operating results and financial condition. Any claims relating to our operations covered by insurance would be subject to deductibles, and since it is possible that a large number of claims may be brought, the aggregate amount of these deductibles could be material. Certain insurance coverage is maintained through mutual protection and indemnity associations, and as a member of such

associations we may be required to make additional payments over and above budgeted premiums if member claims exceed association reserves.

We may be unable to procure adequate insurance coverage at commercially reasonable rates in the future. For example, more stringent environmental regulations have led in the past to increased costs for, and in the future, may result in the lack of availability of, insurance against risks of environmental damage or pollution. A catastrophic oil spill or marine disaster or natural disaster could exceed the insurance coverage, which could harm our business, financial condition and operating results. Any uninsured or underinsured loss could harm our business and financial condition. In addition, the insurance may be voidable by the insurers as a result of certain actions, such as vessels failing to maintain certification with applicable maritime regulatory organizations.

Changes in the insurance markets attributable to terrorist attacks or political change may also make certain types of insurance more difficult to obtain. In addition, the insurance that may be available may be significantly more expensive than existing coverage.

We may experience operational problems with vessels that reduce revenue and increase costs.

Shuttle tankers, FSO and FPSO units, towage and offshore installation vessels and UMS are complex and their operations are technically challenging. Marine transportation and oil production operations are subject to mechanical risks and problems as well as environmental risks. Operational problems may lead to loss of revenue or higher than anticipated operating expenses or require additional capital expenditures. Any of these results could harm our business, financial condition and operating results.

Terrorist attacks, piracy, increased hostilities or war could lead to further economic instability, increased costs and disruption of business.

Terrorist attacks, piracy and the current or future conflicts in the Middle East, West Africa, Libya and elsewhere, and political change may adversely affect our business, operating results, financial condition, and ability to raise capital and future growth. Continuing hostilities in the Middle East especially among Qatar, Saudi Arabia, UAE and Yemen and elsewhere may lead to additional armed conflicts or to further acts of terrorism and civil disturbance in the United States or elsewhere, which may contribute further to economic instability and disruption of oil production and distribution, which could result in reduced demand for our services, impact on our operations and our ability to conduct business.

In addition, oil facilities, shipyards, vessels, pipelines, oil fields or other infrastructure could be targets of future terrorist attacks or warlike operations and our vessels could be targets of pirates, hijackers, terrorists or warlike operations. Any such attacks could lead to, among other things, bodily injury or loss of life, vessel or other property damage, increased vessel operational costs, including insurance costs, and the inability to transport oil to or from certain locations. Terrorist attacks, war, piracy, hijacking or other events beyond our control that adversely affect the distribution, production or transportation of oil to be shipped by us could entitle customers to terminate the charters and impact the use of shuttle tankers under contracts of affreightment, towage and offshore installation vessels under voyage charters and FPSO units under FPSO contracts, which would harm our cash flow and business.

Acts of piracy on ocean-going vessels have continued to be a risk, which could adversely affect our business.

Acts of piracy have historically affected ocean-going vessels trading in regions of the world such as the South China Sea, Gulf of Guinea and the Indian Ocean off the coast of Somalia. While there continues to be a significant risk of piracy in the Gulf of Aden and Indian Ocean, recently there have been increases in the frequency and severity of piracy incidents off the coast of West Africa. If these piracy attacks result in regions in which our vessels are deployed being named on the Joint War Committee Listed Areas, war risk insurance premiums payable for such coverage can increase significantly and such insurance coverage may be more difficult to obtain. In addition, crew costs, including costs which are incurred to the extent we employ on-board armed security guards and escort vessels, could increase in such circumstances. We may not be adequately insured to cover losses from these incidents, which could have a material adverse effect on us. In addition, hijacking as a result of an act of piracy against our vessels, or an increase in cost or unavailability of insurance for our vessels, could have a material adverse impact on our business, financial condition and results of operations.

A cyber-attack could materially disrupt our business

We rely on information technology systems and networks in our operations and the administration of our business. Cyber-attacks have increased in number and sophistication in recent years. Our operations could be targeted by individuals or groups seeking to sabotage or disrupt our information technology systems and networks, or to steal data. A successful cyber-attack could materially disrupt our operations, including the safety of our operations, or lead to unauthorized release of information or alteration of information on our systems. Any such attack or other breach of our information technology systems could have a material adverse effect on our business and results of operations.

Our failure to comply with data privacy laws could damage our customer relationships and expose us to litigation risks and potential fines.

Data privacy is subject to frequently changing rules and regulations, which sometimes conflict among the various jurisdictions and countries in which we provide services and continue to develop in ways which we cannot predict, including with respect to evolving technologies such as cloud computing. The European Union has adopted the General Data Privacy Regulation (or GDPR), a comprehensive legal framework to govern data collection, use and sharing and related consumer privacy rights which took effect in May 2018. The GDPR includes significant penalties for non-compliance. Our failure to adhere to or successfully implement processes in response to changing regulatory requirements in this area could result in legal liability or impairment to our reputation in the marketplace, which could have a material adverse effect on our business, financial condition and results of operations.

The offshore shipping and storage industry is subject to substantial environmental and other regulations, which may significantly limit operations or increase expenses.
Our operations are affected by extensive and changing international, national and local environmental protection laws, regulations, treaties and conventions in force in international waters, the jurisdictional waters of the countries in which our vessels operate, as well as the countries of our vessels' registration, including those governing oil spills, discharges to air and water, and the handling and disposal of hazardous substances and wastes. Many of these requirements are designed to reduce the risk of oil spills and other pollution. In addition, we believe that the heightened environmental, quality and security concerns of insurance underwriters, regulators and charterers will lead to additional regulatory requirements, including enhanced risk assessment and security requirements and greater inspection and safety requirements on vessels. We expect to incur substantial expenses in complying with these laws and regulations, including expenses for vessel modifications and changes in operating procedures. For example, we estimate that the installation of approved ballast water management systems pursuant to the IMO's Ballast Water Management Convention may cost between $2 million and $3 million per vessel when required to be installed.

These requirements can affect the resale value or useful lives of our vessels, require a reduction in cargo capacity, ship modifications or operational changes or restrictions, lead to decreased availability of insurance coverage for environmental matters or result in the denial of access to certain jurisdictional waters or ports, or detention in, certain ports. Under local, national and foreign laws, as well as international treaties and conventions, we could incur material liabilities, including cleanup obligations, in the event that there is a release of petroleum or hazardous substances from our vessels or otherwise in connection with our operations. We could also become subject to personal injury or property damage claims relating to the release of or exposure to hazardous materials associated with our operations. In addition, failure to comply with applicable laws and regulations may result in administrative and civil penalties, criminal sanctions or the suspension or termination of our operations, including, in certain instances, seizure or detention of our vessels. Please see 'Item 4. Information on the Partnership – B. Business Overview – Regulations' for important information on these regulations, including potential impacts on us.
Exposure to currency exchange rate fluctuations results in fluctuations in cash flows and operating results.
We currently are paid partly in Norwegian Krone, British Pound and Brazilian Real under some of our charters and FPSO contracts. The strengthening or weakening of the U.S. Dollar relative to the Norwegian Krone, Brazilian Real, and British Pound may result in significant decreases or increases, respectively, in our revenues and vessel operating expenses. We have entered into foreign currency forward contracts to economically hedge portions of our forecasted expenditures denominated in Norwegian Krone and Euro. In the past we entered into cross-currency swaps to economically hedge the foreign exchange risk on the principal and interest payments on our previously outstanding Norwegian Krone bonds.
Many seafaring employees are covered by collective bargaining agreements and the failure to renew those agreements or any future labor agreements may disrupt operations and adversely affect our cash flows.
A significant portion of seafarers that crew certain of our vessels and Norwegian-based onshore operational staff that provide services to us are employed under collective bargaining agreements. We may become subject to additional labor agreements in the future. We may suffer labor disruptions if relationships deteriorate with the seafarers or the unions that represent them. The collective bargaining agreements may not prevent labor disruptions, particularly when the agreements are being renegotiated. Salaries are typically renegotiated annually or bi-annually for seafarers and annually for onshore operational staff and higher compensation levels will increase our costs of operations. Although these negotiations have not caused labor disruptions in the past, any future labor disruptions could harm our operations and could have a material adverse effect on our business, results of operations and financial condition.
We and certain of our joint venture partners may be unable to attract and retain qualified, skilled employees or crew necessary to operate our business, or may have to pay substantially increased costs for its employees and crew.
Our success depends in large part on our ability to attract and retain highly skilled and qualified personnel. In crewing our vessels, we require technically skilled employees with specialized training who can perform physically demanding work. Any inability we experience in the future to hire, train and retain a sufficient number of qualified employees

could impair our ability to manage, maintain and grow our business.
Teekay Corporation and its affiliates may engage in competition with us.
Teekay Corporation and its affiliates may engage in competition with us. Pursuant to an omnibus agreement we entered into in connection with our initial public offering, Teekay Corporation, Teekay LNG Partners L.P. (NYSE: TGP) (or Teekay LNG) and their respective controlled affiliates (other than us and our subsidiaries) generally have agreed not to engage in, acquire or invest in any business that owns, operates or charters (a) dynamically-positioned shuttle tankers (other than those operating in the conventional oil tanker trade under contracts with a remaining duration of less than three years, excluding extension options), (b) FSO units or (c) FPSO units without the consent of our general partner. The omnibus agreement, however, includes various exceptions to these restrictions, as described in Item 7. Major Unitholders and Related Party Transactions--B. Certain Relationships and Related Party Transactions--Omnibus Agreement.

If there is a change of control of Teekay Corporation or of the general partner of Teekay LNG, the non-competition provisions of the omnibus agreement may terminate, which termination could have a material adverse effect on our business, results of operations and financial condition and our ability to make payments on our debt securities and cash distributions to unitholders.

Our general partner and its other affiliates own a controlling interest in us and have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to those of unitholders.

As at December 31, 2018, affiliates of Brookfield held 59.5% of our outstanding common units and a 51% interest in our general partner, and an affiliate of Teekay Corporation held 13.8% of our outstanding common units and a 49% interest in our general partner. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its members. Furthermore, certain directors and an officer of our general partner are directors or officers of affiliates of our general partner. Conflicts of interest may arise between Teekay Corporation, Brookfield and their affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires Teekay Corporation, Brookfield or their respective affiliates (other than our general partner) to pursue a business strategy that favors us or utilizes our assets, and Teekay Corporation’s and Brookfield’s respective officers and directors have fiduciary duties to make decisions in the best interests of the shareholders of Brookfield and Teekay Corporation, which may be contrary to our interests;
- six directors of our general partner serve as officers, management or directors of Teekay Corporation or Brookfield or their affiliates;
- our general partner is allowed to take into account the interests of parties other than us, such as Brookfield and Teekay Corporation, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;
- our general partner has restricted its liability and reduced its fiduciary duties under the laws of the Marshall Islands, while also restricting the remedies available to our unitholders and unitholders are treated as having agreed to the modified standard of fiduciary duties and to certain actions that may be taken by our general partner, all as set forth in our partnership agreement;
- our general partner approves our annual budget and the amount and timing of our asset purchases and sales, capital expenditures, borrowings, reserves and issuances of additional partnership securities, each of which can affect the amount of cash that is available for distribution to our unitholders;
- in some instances, our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions to the general partner or other holders of our incentive distribution rights;
- our general partner can determine when certain costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict us from paying our general partner or its affiliates for any services rendered to us on terms that are fair and reasonable or entering into additional contractual arrangements with any of these entities;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner may exercise its right to call and purchase common units if it and its affiliates own more than 80.0% of our common units;
- our general partner controls the enforcement of obligations owed to us by it and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

The fiduciary duties of directors of our general partner may conflict with those of the officers and directors of Brookfield and Teekay Corporation.

Our general partner’s officers and directors have fiduciary duties to manage our business in a manner beneficial to us and our partners. However, six directors of our general partner also serve as officers, management or directors of Brookfield or Teekay Corporation and/or other affiliates of Brookfield or Teekay Corporation. Consequently, these directors may encounter situations in which their fiduciary obligations to Brookfield or Teekay Corporation, or their other affiliates, on one hand, and us, on the other hand, are in conflict. The resolution of these conflicts may not always be in the best interest of us or our unitholders.

The international nature of our operations may make the outcome of any bankruptcy proceedings difficult to predict.

We were formed under the laws of the Republic of the Marshall Islands and our subsidiaries were formed or incorporated under the laws of the Marshall Islands, Norway, Singapore and certain other countries besides the United States, and we conduct operations in countries around the world. Consequently, in the event of any bankruptcy, insolvency, liquidation, dissolution, reorganization or similar proceeding involving us or any of our subsidiaries, bankruptcy laws other than those of the United States could apply. We have limited operations in the United States. If we become a debtor under U.S. bankruptcy law, bankruptcy courts in the United States may seek to assert jurisdiction over all of our assets, wherever located, including property situated in other countries. There can be no assurance, however, that we would become a debtor in the United States, or that a U.S. bankruptcy court would be entitled to, or accept, jurisdiction over such a bankruptcy case, or that courts in other countries that have jurisdiction over us and our operations would recognize a U.S. bankruptcy court's jurisdiction if any other bankruptcy court would determine it had jurisdiction.

Our partnership agreement restricts our general partner's fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner.

Our partnership agreement contains provisions that restrict the standards to which our general partner would otherwise be held by Marshall Islands law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. Where our partnership agreement permits, our general partner may consider only the interests and factors that it desires, and in such cases, it has no duty or obligation to give any consideration to any interest of, or factors affecting us, our subsidiaries or our unitholders. Decisions made by our general partner in its individual capacity are made by its members, Brookfield and Teekay Corporation, and not by the board of directors of our general partner. Examples include the exercise of call rights, voting rights with respect to the common units they own, registration rights and their determination whether to consent to any merger or consolidation of the partnership;
- provides that our general partner is entitled to make other decisions in "good faith" if it reasonably believes that the decision is in our best interests;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the Conflicts Committee of the board of directors of our general partner and not involving a vote of common unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud, willful misconduct or gross negligence.

Fees and cost reimbursements, which our general partner determines for services provided to us, may be substantial and reduce our cash available for distribution to our unitholders and for debt service.

We pay fees for any services provided to us and our operating subsidiaries by certain subsidiaries of Teekay Corporation, and we reimburse our general partner for all expenses it incurs on our behalf. These fees are negotiated on our behalf by our general partner, and our general partner can determine when certain costs are reimbursed. The payment of any fees to Teekay Corporation and reimbursement of expenses to our general partner could adversely affect our ability to pay cash distributions to unitholders and debt service.

Our general partner, which is owned by Brookfield and Teekay Corporation, makes all decisions on our behalf, subject to the limited voting rights of our unitholders. Even if public unitholders are dissatisfied, they cannot remove our general partner without the consent of Brookfield and Teekay Corporation.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or its board of directors and have no right to elect our general partner or its board of directors on an annual or other continuing basis. Brookfield and Teekay Corporation, which own our general partner, appoint our general partner's board of directors. Our general partner makes all decisions on our behalf. If the unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner.

The vote of the holders of at least 66 2/3% of all outstanding common units voting together as a single class is required to remove the general partner. In addition, unitholders' voting rights are further restricted by our partnership agreement provision providing that any units held by a person that owns 20% or more of any class or series of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of

management.
Control of our general partner may be transferred to a third party without unitholder consent.
Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. In addition, our partnership agreement does not restrict the ability of the members of our general partner from transferring their respective membership interests in our general partner to a third party. In the event of any such transfer, the new members of our general partner would be in a position to replace the board of directors and officers of our general partner with their own choices and to control the decisions taken by the board of directors and officers. Pursuant to the terms of the general partner LLC agreement, Teekay Corporation has agreed to certain restrictions on its ability to transfer its membership interest in our general partner without the prior approval of Brookfield and, if Brookfield agrees to sell all or substantially all of its common units in us and membership interests in our general partner, Brookfield may require Teekay Corporation to participate in the sale on the same terms and conditions as Brookfield.
In establishing cash reserves, our general partner may reduce the amount of cash available for distribution to unitholders.
Our partnership agreement requires our general partner to deduct from our available cash reserves that it determines are necessary to fund our future operating expenditures. These reserves affect the amount of cash available for distribution by us to our unitholders. In addition, our

partnership agreement requires our general partner each quarter to deduct from operating surplus estimated maintenance capital expenditures, as opposed to actual expenditures, which could impact the amount of available cash for distribution.

Unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully distributed to them. Under the Marshall Islands Limited Partnership Act (or Marshall Islands Act), we may not make a distribution to unitholders to the extent that at the time of the distribution, after giving effect to the distribution, all our liabilities, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specified property of ours, exceed the fair value of our assets, except that the fair value of property that is subject to a liability for which the recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds that liability. Marshall Islands law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Marshall Islands law will be liable to the limited partnership for the distribution amount. Purchasers of units who become limited partners are liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to the purchaser at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement.

We have been organized as a limited partnership under the laws of the Republic of the Marshall Islands, which does not have a well-developed body of partnership law.

Our partnership affairs are governed by our partnership agreement and by the Marshall Islands Act. The provisions of the Marshall Islands Act resemble provisions of the limited partnership laws of a number of states in the United States, most notably Delaware. The Marshall Islands Act also provides that, for nonresident limited partnerships such as us, it is to be applied and construed to make the laws of the Marshall Islands, with respect to the subject matter of the Marshall Islands Act, uniform with the laws of the State of Delaware and, so long as it does not conflict with the Marshall Islands Act or decisions of certain Marshall Islands courts, the non-statutory law (or case law) of the courts of the State of Delaware is adopted as the law of the Marshall Islands. There have been, however, few, if any, court cases in the Marshall Islands interpreting the Marshall Islands Act, in contrast to Delaware, which has a fairly well-developed body of case law interpreting its limited partnership statute. Accordingly, we cannot predict whether Marshall Islands courts would reach the same conclusions as Delaware courts. For example, the rights of our unitholders and the fiduciary responsibilities of our general partner under Marshall Islands law are not as clearly established as under judicial precedent in existence in Delaware. As a result, unitholders may have more difficulty in protecting their interests in the face of actions by our general partner and its officers and directors than would unitholders of a limited partnership formed in the United States.

Because we are organized under the laws of the Marshall Islands, it may be difficult to serve us with legal process or enforce judgments against us, our directors or our management.

We are organized under the laws of the Marshall Islands, and all of our assets are located outside of the United States. Our business is operated primarily from our offices in Bermuda, Norway, Brazil, the United Kingdom, Singapore and the Netherlands. In addition, our general partner is a Marshall Islands limited liability company and a majority of its directors and officers are non-residents of the United States, and all or a substantial portion of the assets of these non-residents are located outside the United States. As a result, it may be difficult or impossible to bring an action against us or against these individuals in the United States. Even if successful in bringing an action of this kind, the laws of the Marshall Islands and of other jurisdictions may prevent or restrict the enforcement of a judgment against our assets or the assets of our general partner or its directors and officers.

Tax Risks

In addition to the following risk factors, you should read Item 4E – Taxation of the Partnership, Item 10 – Additional Information – Material U.S. Federal Income Tax Considerations and Item 10 – Additional Information – Non-United States Tax Considerations for a more complete discussion of the expected material U.S. federal and non-U.S. income tax considerations relating to us and the ownership and disposition of our common units.

U.S. tax authorities could treat us as a "passive foreign investment company," which could have adverse U.S. federal income tax consequences to U.S. holders.

A non-U.S. entity treated as a corporation for U.S. federal income tax purposes will be treated as a "passive foreign investment company" (or PFIC), for such purposes in any taxable year for which either (a) at least 75% of its gross income consists of "passive income," or (b) at least 50% of the average value of the entity's assets is attributable to assets that produce or are held for the production of "passive income." For purposes of these tests, "passive income" includes dividends, interest, gains from the sale or exchange of investment property and rents and royalties (other than rents and royalties that are received from unrelated parties in connection with the active conduct of a trade or business). By contrast, income derived from the performance of services does not constitute "passive income."

There are legal uncertainties involved in determining whether the income derived from our time-chartering activities constitutes rental income or income derived from the performance of services, including the decision in Tidewater Inc. v. United States, 565 F.3d 299 (5th Cir. 2009), which held that income derived from certain time-chartering activities should be treated as rental income rather than services income for purposes of a foreign sales corporation provision of the Internal Revenue Code of 1986, as amended (or the Code). However, the Internal Revenue Service (or IRS) stated in an Action on Decision (AOD 2010-01) that it disagrees with, and will not acquiesce to, the way that the rental versus services framework was applied to the facts in the Tidewater decision, and in its discussion stated that the time charters at issue in Tidewater would be treated as producing services income for PFIC purposes. The IRS's statement with respect to Tidewater cannot be relied upon or otherwise cited as precedent by taxpayers. Consequently, in the absence of any binding legal authority specifically relating to the statutory provisions governing PFICs, there can be no assurance that the IRS or a court would not follow the Tidewater decision in interpreting the PFIC provisions of the Code. Nevertheless, based on the current composition of our assets and operations (and those of our subsidiaries), we intend to take the position that we are not now and have never been a PFIC. No assurance can be given, however, that this position would be sustained by a court if contested by the IRS, or that we would not constitute a PFIC for any future taxable year if there were to be changes in our assets, income or operations.

If the IRS were to determine that we are or have been a PFIC for any taxable year during which a U.S. Holder (as defined below under Item 10 – Additional Information – Material U.S. Federal Income Tax Considerations) held units, such U.S. Holder would face adverse tax consequences. For a more comprehensive discussion regarding the tax consequences to U.S. Holders if we are treated as a PFIC, please read Item 10 – Additional Information: Material U.S. Federal Income Tax Considerations — United States Federal Income Taxation of U.S. Holders – Consequences of Possible PFIC Classification.

We are subject to taxes, which reduces our cash available for distribution to partners.

We or our subsidiaries are subject to tax in certain jurisdictions in which we or our subsidiaries are organized, own assets or have operations, which reduces the amount of our cash available for distribution. In computing our tax obligations in these jurisdictions, we are required to take various tax accounting and reporting positions on matters that are not entirely free from doubt and for which we have not received rulings from the governing authorities. We cannot assure you that upon review of these positions, the applicable authorities will agree with our positions. A successful challenge by a tax authority could result in additional tax imposed on us or our subsidiaries, further reducing the cash available for distribution. We have established reserves in our financial statements that we believe are adequate to cover our liability for any such additional taxes. We cannot assure you, however, that such reserves will be sufficient to cover any additional tax liability that may be imposed on our subsidiaries. In addition, changes in our operations or ownership could result in additional tax being imposed on us or on our subsidiaries in jurisdictions in which operations are conducted. For example, Brookfield Business Partners L.P. owns less than 50% of the value of our outstanding units and therefore we believe that we do not satisfy the requirements of the exemption from U.S. taxation under Section 883 of the Code and our U.S. source income is subject to taxation under Section 887 of the Code. The amount of such tax will depend upon the amount of income we earn from voyages into or out of the United States, which is not within our complete control.

Unitholders may be subject to income tax in one or more non-U.S. countries, including Canada, as a result of owning our units if, under the laws of any such country, we are considered to be carrying on business there. Such laws may require unitholders to file a tax return with, and pay taxes to, those countries.

The unitholders will be subject to tax in one or more countries, including Canada, as a result of owning our units if, under the laws of any such country, we are considered to be carrying on business there. If unitholders are subject to tax in any such country, unitholders may be required to file a tax return with, and pay taxes to, that country based on their allocable share of our income. We may be required to reduce distributions to unitholders on account of any withholding obligations imposed upon us by that country in respect of such allocation to unitholders. The United States may not allow a tax credit for any foreign income taxes that unitholders directly or indirectly incur.

Item 4. Information on the Partnership

A. Overview, History and Development

Overview and History

We are an international midstream services provider of marine transportation, oil production, storage, long-distance towage and offshore installation and maintenance and safety services to the offshore oil industry focusing on the deep-water offshore oil regions of the North Sea, Brazil and the East Coast of Canada. We were formed as a Marshall Islands limited partnership in August 2006 by Teekay Corporation (NYSE: TK), a portfolio manager and project developer in the marine midstream space. In September 2017, affiliates of Brookfield Business Partners L.P. (NYSE:

BBU) (TSX: BBU.UN) (or Brookfield) purchased from an affiliate of Teekay Corporation a 49% interest in our general partner and purchased approximately 60% of our common units and certain warrants to purchase additional common units from us. In July 2018, Brookfield exercised its option to acquire an additional 2% interest in our general partner from an affiliate of Teekay Corporation. We seek to leverage the expertise, relationships and reputation of Brookfield and Teekay Corporation to pursue long-term growth opportunities. Our growth strategy focuses primarily on expanding our fleet of shuttle tankers and FPSO units under medium-to-long term charter contracts. Our near-to-medium-term business strategy is primarily to focus on extending contracts and redeploying existing assets on long-term charters, repaying or refinancing scheduled debt obligations and pursuing additional strategic growth projects. Over the long-term, we intend to continue our practice of primarily acquiring or constructing vessels as needed for approved projects only after long-term charters for the projects have been awarded to us, rather than ordering vessels on a speculative basis. We have entered and may enter into joint ventures and partnerships with companies that may provide increased access to such charter opportunities or may engage in vessel or business acquisitions. We are structured as a master limited partnership. As of December 31, 2018, the public held a total of 26.7% of our outstanding common units, Brookfield held 59.5% of our outstanding common units and 51% of the general partner interest, and an affiliate of Teekay Corporation held the remaining 13.8% of our outstanding common units and 49% of the general partner interest.

As of December 31, 2018, our fleet consisted of:

- FPSO Units. Our FPSO fleet consisted of six units, in which we have 100% ownership interests, five of which are operating under FPSO contracts with major energy companies in the North Sea, United Kingdom and Brazil and one of which currently is in lay-up. We also have two FPSO units, in which we have 50% ownership interests, which are on charter in Brazil. We use the FPSO units to provide production, processing and storage services to oil companies operating offshore oil field installations. The FPSO contracts, have an average remaining term of approximately 3.5 years. As of December 31, 2018, our FPSO units had a total production capacity of approximately 0.4 million barrels of oil per day.
- Shuttle Tankers. Our shuttle tanker fleet consisted of 26 vessels that operate under fixed-rate contracts of affreightment (or CoAs), time charters and bareboat charters, two vessels that are currently in lay-up, six shuttle tanker newbuildings, that, following delivery, will operate under fixed-rate CoAs and time charters, and the HiLoad DP unit, which is currently in lay-up. Of these 35 shuttle tankers, four are owned through 50%-owned subsidiaries and two were chartered-in. The remaining vessels are owned 100% by us. All of our operating shuttle tankers, with the exception of two shuttle tankers that are currently trading as conventional tankers and the HiLoad DP unit, provide transportation services to energy companies in the North Sea, Brazil and the East Coast of Canada under CoAs, time charters or bareboat charters. Our shuttle tankers occasionally service the conventional spot tanker market. The average term of the CoAs, weighted based on vessel years, is 4.0 years. The time charters and bareboat charters have an average remaining contract term of approximately 4.0 years. As of December 31, 2018, our shuttle tanker fleet, including newbuildings, had a total cargo capacity of approximately 4.4 million dead-weight tonnes (or dwt), representing approximately 34% of the total tonnage of the world shuttle tanker fleet.
- FSO Units. Our FSO fleet consisted of five units, in which we have 100% ownership interests, and one unit, the Apollo Spirit, in which we have an 89% ownership interest. Our FSO units operate under fixed-rate contracts, with an average remaining term of approximately 3.1 years. As of December 31, 2018, our FSO units had a total cargo capacity of approximately 0.7 million dwt.
- UMS. Our UMS fleet consisted of one unit, the Arendal Spirit UMS, in which we have a 100% ownership interest and which is currently in lay-up.
- Towage and Offshore Installation Vessels. Our long-distance towage and offshore installation fleet consisted of eight operating vessels and two vessels that are currently in lay-up. We have 100% ownership interests in all our towage and offshore installation vessels. All of our operational towage and offshore installation vessels operate under voyage-charter and spot towage contracts.
- Conventional Tankers. Our conventional tanker fleet consisted of two conventional tankers, which are in-chartered until March 2019 with additional one-year extension options. Both vessels are currently trading in the spot conventional tanker market. As of December 31, 2018, our conventional tankers had a total cargo capacity of approximately 0.2 million dwt.

We were formed under the laws of the Republic of the Marshall Islands as Teekay Offshore Partners L.P. and maintain our principal executive offices at 4th Floor, Belvedere Building, 69 Pitts Bay Road, Hamilton, HM 08, Bermuda. Our telephone number at such address is (441) 298-2530.

The SEC maintains an Internet site at www.sec.gov, that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. Our website is www.teekay.com/business/offshore/. The information contained on our website is not part of this annual report.

Potential Additional Shuttle Tanker, FSO and FPSO Projects

Please see Item 5. Operating and Financial Review and Prospects – Management's Discussion and Analysis of Financial Condition and Results of Operations – Potential Additional Shuttle Tanker, FSO and FPSO Projects for a description of possible future vessel acquisitions.

B. Business Overview

FPSO Segment

FPSO units are offshore production facilities that are ship-shaped or cylindrical-shaped and store processed crude oil in tanks located in the hull of the vessel. FPSO units are typically used as production facilities to develop marginal oil fields or deepwater areas remote from existing pipeline infrastructure. Of four major types of floating production systems, FPSO units are the most common type. Typically, the other types of floating production systems do not have significant storage and need to be connected into a pipeline system or use an FSO unit for storage. FPSO units are less weight-sensitive than other types of floating production systems and their extensive deck area provides flexibility in process plant layouts. In addition, the ability to utilize surplus or aging tanker hulls for conversion to an FPSO unit provides a relatively inexpensive solution compared to the new construction of other floating production systems. A majority of the cost of an FPSO unit comes from its top-side production equipment and thus, FPSO units are expensive relative to conventional tankers. An FPSO unit carries on board all the necessary production and processing facilities normally associated with a fixed production platform. As the name suggests, FPSO units are not fixed permanently to the seabed but are designed to be moored at one location for long periods of time. In a typical FPSO unit installation, the untreated well-stream is brought to the surface via sub-sea equipment on the sea floor that is connected to the FPSO unit by flexible flow lines called risers. The risers carry the mix of oil, gas and water from the ocean floor to the vessel, which processes it on board. The resulting crude oil is stored in the hull of the vessel and subsequently transferred to tankers either via a buoy or tandem loading system for transport to shore.

Traditionally for large field developments, the major oil companies have owned and operated new, custom-built FPSO units. FPSO units for smaller fields have generally been provided by independent FPSO contractors under life-of-field production contracts, where the contract's duration is for the useful life of the oil field. FPSO units have been used to develop offshore fields around the world since the late 1970s. As of December 31, 2018, there were approximately 174 FPSO units active and operating, another 20 idle FPSO units and 14 FPSO units on order in the world fleet. At December 31, 2018, we owned six FPSO units, in which we have 100% ownership interests, one of which is in lay-up, and two FPSO units in which we have 50% ownership interests. Most independent FPSO contractors have backgrounds in marine energy transportation, oil field services or oil field engineering and construction. Other major independent FPSO contractors are SBM Offshore N.V., BW Offshore, MODEC, Bumi Armada, Yinson Holdings and Bluewater.

The following table provides additional information about our FPSO units as of December 31, 2018:

Vessel	Production Capacity (bbl/day)	Built	Ownership		Field name and location	Charterer	Contract End Date
Pioneiro de Libra (1)	50,000	2017	50	%	Libra, Brazil	Petrobras	November 2029 (2)
Petrojarl Knarr	63,000	2014	100	%	Knarr, Norway	Shell	March 2025 (3)
Cidade de Itajai (4)	80,000	2012	50	%	Bauna and Piracaba, Brazil	Petrobras	February 2022 (5)
Voyageur Spirit	30,000	2008	100	%	Huntington, U.K.	Premier	April 2020
Petrojarl Cidade de Rio das Ostras (6)	25,000	2008	100	%	Tartaruga Verde, Brazil	Petrobras	March 2019
Piranema Spirit	30,000	2007	100	%	Piranema, Brazil	Petrobras	March 2019 (7)
Petrojarl I	46,000	1986	100	%	Atlanta, Brazil	QGEP	May 2023
Petrojarl Varg	57,000	1998	100	%		Lay-up	
Total capacity	381,000						

(1) The Pioneiro de Libra was converted to an FPSO unit in 2017. The original hull was built in 1995.
(2) The charterer has options to extend the contract to November 2037.
(3) The contract has a 10-year duration with a firm period expiring in March 2025, although the charterer has the annual right to terminate the contract after March 2021 subject to payment of certain termination fees for early cancellation. The charterer has options to extend the service contract to 2035.
(4) The Cidade de Itajai was converted to an FPSO unit in 2012. The original hull was built in 1985.
(5) The charterer has options to extend the contract to February 2028.
(6) The Petrojarl Cidade de Rio das Ostras was converted to an FPSO unit in 2008. The original hull was built in 1981. The charterer has an option to extend the contract by one month to April 2019.
(7) Subsequent to December 31, 2018, we secured a three-year contract extension with Petrobras to extend the employment of the Piranema Spirit FPSO unit until February 2022, subject to charterer termination rights with 10 months' notice.

During 2018, approximately 42% of our consolidated net revenues were earned by our FPSO units, compared to approximately 45% in 2016 and 46% in 2016. Please read Item 5 – Operating and Financial Review and Prospects: Results of Operations.

Shuttle Tanker Segment

A shuttle tanker is a specialized ship designed to transport crude oil and condensates from offshore oil field installations to onshore terminals and refineries. Shuttle tankers are equipped with sophisticated loading systems and dynamic positioning systems that allow the vessels to load cargo safely and reliably from oil field installations, even in harsh weather conditions. Shuttle tankers were developed in the North Sea as an alternative to pipelines. The first cargo from an offshore field in the North Sea was shipped in 1977, and the first dynamically-positioned shuttle tankers were introduced in the early 1980s. Shuttle tankers are often described as “floating pipelines” because these vessels typically shuttle oil from offshore installations to onshore facilities in much the same way a pipeline would transport oil along the ocean floor.

Our shuttle tankers are primarily subject to long-term, fixed-rate time-charter contracts for a specific offshore oil field or under contracts of affreightment for various fields. The number of voyages performed under these contracts of affreightment normally depends upon the oil production of each field. Competition for charters is based primarily upon price, availability, the size, technical sophistication, age and condition of the vessel and the reputation of the vessel’s manager. Although the size of the world shuttle tanker fleet has been relatively unchanged in recent years, conventional tankers could be converted into shuttle tankers by adding specialized equipment to meet customer requirements. Shuttle tanker demand may also be affected by the possible substitution of sub-sea pipelines to transport oil from offshore production platforms. The shuttle tankers in our contract of affreightment fleet may operate in the conventional spot market during downtime or maintenance periods for oil field installations or otherwise, which provides greater capacity utilization for the fleet.

As of December 31, 2018, there were approximately 92 vessels in the world shuttle tanker fleet (including 19 newbuildings), the majority of which operate in the North Sea and Brazil. Shuttle tankers also operate off the East Coast of Canada and in the U.S. Gulf. As of December 31, 2018, we owned 33 shuttle tankers (including six vessels under construction and the HiLoad DP unit), in which our ownership interests ranged from 50% to 100%, and chartered-in an additional two shuttle tankers. Other shuttle tanker owners include Knutsen NYK Offshore Tankers AS, KNOT Offshore Partners LP, SCF Group, Viken Shipping and AET, which as of December 31, 2018 controlled fleets ranging from 5 to

35 shuttle tankers each. We believe that we have competitive advantages in the shuttle tanker market as a result of the quality, type and dimensions of our vessels combined with our market share in the North Sea, Brazil and the East Coast of Canada.

The following tables provide additional information about our shuttle tankers, including newbuildings, as of December 31, 2018:

Vessel	Capacity (dwt)	Built	Ownership	Positioning System	Operating Region	Contract Type[1]	Charterer	Contract End Date
Scott Spirit	109,300	2011	100%	DP2	North Sea	CoA	BP, Chevron, Draugen Transport, Aker BP, Total, Repsol, Dana Petroleum, OMV, Wintershall, Idemitsu, DEA, Lundin, ConocoPhillips PGING, Enquest, Premier Oil, Shell, Equinor, Taqa Bratani, Nautical, Dyas, Molgrowest[2]	
Amundsen Spirit	109,300	2010	100%	DP2	North Sea	CoA		
Grena Knutsen	148,600	2003	In-chartered (until September 2019)	DP2	North Sea	CoA		
Stena Natalita	108,100	2001	50%[3]	DP2	North Sea	CoA		
Navion Oslo	100,300	2001	100%	DP2	North Sea	CoA		
Navion Oceania	126,400	1999	100%	DP2	North Sea	CoA		
Navion Hispania	126,200	1999	100%	DP2	North Sea	CoA		
Heather Knutsen	148,600	2005	In-chartered (until February 2020)	DP2	North Sea	CoA		
Samba Spirit	154,100	2013	100%	DP2	Brazil	TC	Shell	June 2023
Lambada Spirit	154,000	2013	100%	DP2	Brazil	TC	Shell	August 2023
Bossa Nova Spirit	155,000	2013	100%	DP2	Brazil	TC	Shell	November 2023
Sertanejo Spirit	155,000	2013	100%	DP2	Brazil	TC	Shell	January 2024
Peary Spirit	109,300	2011	100%	DP2	North Sea	TC	Equinor [4]	March 2019
Nansen Spirit	109,300	2010	100%	DP2	North Sea	TC	Equinor [4]	March 2019
Stena Sirita	126,900	1999	50%[3]	DP2	North Sea	TC	Esso	August 2019
Navion Anglia	126,400	1999	100%	DP2	North Sea	TC	Equinor [4]	March 2019
Beothuk Spirit	148,200	2017	100%	DP2	Canada	TC	ExxonMobil, Canada Hibernia, Chevron, Husky, Mosbacher, Murphy, Nalcor, Equinor, Suncor[2]	May 2030
Norse Spirit	148,200	2017	100%	DP2	Canada	TC		May 2030
Dorset Spirit	148,200	2018	100%	DP2	Canada	TC		May 2030
Navion Gothenburg	152,200	2006	50%[3]	DP2	Brazil	BB	Petrobras[5]	July 2020
Navion Stavanger	148,700	2003	100%	DP2	Brazil	BB	Petrobras[5]	July 2019

Petroatlantic	93,000	2003	100%	DP2	North Sea	TC	Teekay Corporation	March 2022
Petronordic	93,000	2002	100%	DP2	North Sea	TC	Teekay Corporation	March 2022
Navion Bergen	105,600	2000	100%	DP2	Brazil	BB	Petrobras(5)	April 2020
Nordic Brasilia	151,300	2004	100%	DP	Far-East	Spot		
Nordic Rio	151,300	2004	50%(3)	DP	Far-East	Spot		
Aurora Spirit(6)	129,830	2019	100%	DP2	North Sea	NB		
Rainbow Spirit(6)	129,830	2020	100%	DP2	North Sea	NB		
Tide Spirit(6)	129,830	2020	100%	DP2	North Sea	NB		
Current Spirit(6)	129,830	2020	100%	DP2	North Sea	NB		
SHI Hull No. 2286(6)	103,500	2020	100%	DP2	North Sea	NB		
SHI Hull No. 2287(6)	103,500	2021	100%	DP2	North Sea	NB		
Nordic Spirit	151,300	2001	100%	DP	Far-East	Lay-up		
Alexita Spirit	127,000	1998	100%	DP2	Far-East	Lay-up		
HiLoad DP Unit(7)	n/a	2010	100%	DP	Norway	Lay-up		
Total capacity	4,411,120							

(1) "CoA" refers to contracts of affreightment, "TC" refers to time charters, "BB" refers to bareboat charters, "NB" refers to newbuilding.

(2) Not all of the contracts of affreightment or time-charter customers utilize every ship in the contract of affreightment or time-charter fleet.

(3) Owned through a 50% owned subsidiary. The parties share in the profits and losses of the subsidiary in proportion to each party's relative ownership.

(4) Under the terms of a master agreement with Equinor, the vessels are chartered under individual fixed-rate annually renewable time-charter contracts. The number of vessels may be adjusted annually based on the requirements of the fields serviced. It is expected that between one and three vessels will be required by Equinor annually. The vessels currently on time-charter to Equinor may be replaced by vessels currently servicing contracts of affreightment or other time-charter contracts.

(5) Charterer has the right to purchase the vessel at end of the bareboat charter.

(6) Four of the six Samsung newbuildings will operate in the North Sea contract of affreightment fleet and two will operate under the master agreement with Equinor.
(7) Self-propelled DP system that attaches to and keeps conventional tankers in position when loading from offshore installations.

On the Norwegian continental shelf, regulations have been imposed on the operators of offshore fields related to vaporized crude oil that is formed and emitted during loading operations and which is commonly referred to as Volatile Organic Compounds (or VOC). To assist the oil companies in their efforts to meet the regulations on VOC emissions from shuttle tankers, we have played an active role in establishing and participating in a unique co-operation among 25 owners of offshore fields in the Norwegian sector. The purpose of the co-operation is to implement VOC reduction systems on selected shuttle tankers to reduce and report VOC emissions according to Norwegian authorities' requirements. Currently, we own VOC systems on 8 of our shuttle tankers. In addition, four of the newbuildings on order will have VOC recovery units installed. The oil companies that participate in the co-operation have also engaged us to undertake the day-to-day administration, technical follow-up and handling of payments through a dedicated clearing house function.

During 2018, approximately 42% of our consolidated net revenues were earned by the vessels in the shuttle tanker segment, compared to approximately 45% in 2017 and 42% in 2016. Please read Item 5 – Operating and Financial Review and Prospects: Results of Operations.

Historically, the utilization of shuttle tankers in the North Sea is higher in the winter months, as favorable weather conditions in the summer months provide opportunities for repairs and maintenance to our vessels and to the offshore oil platforms. Downtime for repairs and maintenance generally reduces oil production and, thus, transportation requirements.

FSO Segment

FSO units provide on-site storage for oil field installations that have no storage facilities or that require supplemental storage. An FSO unit is generally used in combination with a jacked-up fixed production system, floating production systems that do not have sufficient storage facilities or as supplemental storage for fixed platform systems, which generally have some on-board storage capacity. An FSO unit is usually of similar design to a conventional tanker, but has specialized loading and off-take systems required by field operators or regulators. FSO units are moored to the seabed at a safe distance from a field installation and receive cargo from the production facility via a dedicated loading system. An FSO unit is also equipped with an export system that transfers cargo to shuttle or conventional tankers. Depending on the selected mooring arrangement and where they are located, FSO units may or may not have any propulsion systems. FSO units are usually conversions of older shuttle tankers or conventional oil tankers. These conversions, which include installation of a loading and off-take system and hull refurbishment, can generally extend the lifespan of a vessel as an FSO unit by up to 20 years over the normal shuttle tanker lifespan of 20 years.

Our FSO units are generally placed on long-term, fixed-rate time charter or bareboat charter contracts as an integrated part of the field development plan, which provides stable cash flow to us.

As of December 31, 2018, there were approximately 90 FSO units operating and one FSO unit on order in the world fleet, and we had six FSO units in which our ownership interests ranged from 89% to 100%. The major markets for FSO units are Asia, West Africa, Northern Europe, the Mediterranean and the Middle East. Our primary competitors in the FSO market are conventional tanker owners who have access to tankers available for conversion, and oil field services companies and oil field engineering and construction companies who compete in the floating production system market. Competition in the FSO market is primarily based on price, expertise in FSO operations, management of FSO conversions and relationships with shipyards, as well as the ability to access vessels for conversion that meet customer specifications.

The following table provides additional information about our FSO units as of December 31, 2018:

Vessel	Capacity (dwt)	Built	Ownership	Field name and location	Contract Type	Charterer	Contract End Date
Randgrid (1)(2)	124,500	1995	100%	Gina Krog, Norway	Time charter	Equinor	October 2020
Suksan Salamander (1)	78,200	1993	100%	Bualuang, Thailand	Bareboat	Teekay Corporation	August 2024
Pattani Spirit (3)	113,800	1988	100%	Platong, Thailand	Bareboat	Teekay Corporation	April 2019
Dampier Spirit (1)	106,700	1987	100%	Stag, Australia	Time charter	Jadestone Energy	August 2024
Falcon Spirit (4)	124,500	1986	100%	Al Rayyan, Qatar	Time charter	Qatar Petroleum	June 2022
Apollo Spirit (5)	129,000	1978	89%	Banff, U.K.	Bareboat	Teekay Corporation	July 2020
Total capacity	676,700						

(1) Charterer has option to extend the time charter.
(2) The vessel was converted into an FSO unit in 2017.
(3) In early-2019 an agreement was entered into to sell the vessel to Teekay Corporation in April 2019.
(4) Charterer has early termination rights for an 18-month notice period.
(5) Charterer is required to charter the vessel for as long as Teekay Corporation's Petrojarl Banff FPSO unit produces in the Banff field in the North Sea.

During 2018, approximately 11% of our consolidated net revenues were earned by the vessels in the FSO segment, compared to 7% in 2017 and 5% in 2016. Please read Item 5 – Operating and Financial Review and Prospects: Results of Operations.

UMS Segment

UMS are used primarily for offshore accommodation, storage and support for maintenance and modification projects on existing offshore installations, or during the installation and decommissioning of large floating exploration, production and storage units, including FPSO units, floating liquefied natural gas (or FLNG) units and floating drill rigs. Our unit is available for world-wide operations, excluding operations on the Norwegian Continental Shelf, and includes DP3 keeping systems that are capable of operating in deep water and harsh weather. The unit is currently in lay-up in Norway. As of December 31, 2018, there were approximately 63 DP UMS operating and 9 units on order in the world fleet.

We entered into a settlement agreement with Petrobras with respect to various disputes relating to the previously-terminated charter contracts of the HiLoad DP unit and Arendal Spirit UMS. As part of the settlement agreement, Petrobras has agreed to pay a total amount of $96 million to us, $55 million of which was received during 2018. The remaining $41 million is to be paid in two separate installments of $22 million and $19 million by the end of 2020 and 2021, respectively, subject to certain potential offsets described below.

If in the ordinary course of business and prior to the end of 2021, new charter contracts are entered into with Petrobras in respect of our specific assets (being Arendal Spirit UMS, Petrojarl Cidade de Rio das Ostras FPSO unit and Piranema Spirit FPSO unit), the deferred $41 million (payable in two installments in 2020 and 2021, respectively) will partly be reduced by revenue actually received in this same period from such new contracts.

The following table provides additional information about our UMS as of December 31, 2018:

Vessel	Berths	Built	Ownership		Location	Contract type
Arendal Spirit	500	2015	100	%	Norway	Lay-up

During 2018, approximately 3% of our consolidated net revenues was earned by the UMS segment compared to 0% in 2017 and 3% in 2016. Please read Item 5 – Operating and Financial Review and Prospects: Results of Operations.

Towage and Offshore Installation Vessels Segment

Long-distance towage and offshore installation vessels are used for the towage, station-keeping, installation and decommissioning of large floating objects such as exploration, production and storage units, including FPSO units, FLNG units and floating drill rigs. We operate with high-end vessels which can be defined as long-distance towage and offshore installation vessels with a bollard pull of generally greater than 200 tonnes and a fuel capacity of at least 35-40 days of operation. Our focus is on intercontinental towage requiring trans-ocean movements.

Our vessels operate on voyage-charter and spot contracts. Voyage-charter contract revenue is less volatile than revenue from spot market rates, as project budgets are prepared and maintained well in advance of the contract commencement.

As of December 31, 2018, there were approximately 17 long-distance towage and offshore installation vessels with a bollard pull greater than approximately 200 tonnes, which is the minimum specification for vessels in direct competition with us, operating in the world fleet. At December 31, 2018, our towage fleet included ten long-distance towage and offshore installation vessels, in which we have 100% ownership interests.

The following table provides additional information about our towage and offshore installation vessels as of December 31, 2018:

Vessel	Bollard Pull (tonnes)	Built	Ownership		Contract Type
ALP Keeper	302	2018	100	%	Voyage-charter
ALP Defender	305	2017	100	%	Voyage-charter
ALP Sweeper	303	2017	100	%	Voyage-charter
ALP Striker	309	2016	100	%	Voyage-charter

ALP Centre	298	2010	100	%	Voyage-charter
ALP Guard	285	2009	100	%	Voyage-charter
ALP Winger	208	2007	100	%	Voyage-charter
ALP Ippon	198	2006	100	%	Voyage-charter
ALP Forward	219	2007	100	%	Lay-up
ALP Ace	192	2006	100	%	Lay-up
	2,619				

During 2018, approximately 2% of our consolidated net revenues were earned by the vessels in the towage and offshore installation vessels segment compared to 1% in 2017 and 2% in 2016. Please read Item 5 – Operating and Financial Review and Prospects: Results of Operations.

Conventional Tanker Segment

Conventional oil tankers are used primarily for transcontinental seaborne transportation of oil. As used in this discussion, "conventional" oil tankers exclude those vessels that can carry dry bulk and ore, tankers that currently are used for storage purposes and shuttle tankers.

In March 2016, we sold our two conventional tankers and subsequently chartered-in both vessels for three years each; both with additional one-year extension options. Both vessels are trading in the spot conventional tanker market and are expected to be redelivered to their owners in March 2019.

The following table provides information about our conventional tankers as of December 31, 2018:

Vessel	Capacity (dwt)	Built	Ownership	Contract Type
Blue Pride	115,000	2004	In-chartered (until March 2019)	Spot(1)
Blue Power	106,400	2003	In-chartered (until March 2019)	Spot(1)
Total capacity	221,400			

(1) "Spot" refers to spot conventional tanker market.

During 2018, approximately 1% of our consolidated net revenues from continuing operations were earned by the vessels in the conventional tanker segment, compared to 1% in 2017 and 2% in 2016. Please read Item 5 – Operating and Financial Review and Prospects: Results of Operations.

Business Strategies

Our primary business strategies include the following:

- Providing Superior, Cost-Effective Customer Service by Maintaining High Reliability, Safety, Environmental and Quality Standards. Energy companies demand partners that have a reputation for high reliability, safety, environmental and quality standards. We intend to continue to leverage our operational expertise and customer relationships to further expand a sustainable competitive advantage with consistent delivery of superior customer service, including working together with customers in seeking to reduce their production costs and find efficiencies.
- Focusing on Generating Stable and Recurring Cash Flows from Long-Term Contracts with Creditworthy Customers. We intend to maintain and grow our cash flows by focusing on strong customer relationships and actively seeking the extension and renewal of existing charter contracts, entering into new medium- to long-term fixed-rate charter contracts with current customers, and identifying new business opportunities with other creditworthy customers for our current fleet. By focusing primarily on maximizing returns from our existing asset base, we believe we can generate stable and reliable cash flows while providing customers with quick-to-market and lower cost solutions. We believe we are well-positioned to extend contracts and redeploy existing assets by leveraging our engineering and operational expertise with our global marketing organization and extensive customer relationships.
- Acquiring Vessels with Existing Contracts or Constructing Additional Assets to Serve Under Medium- to Long-Term, Fixed-Rate Contracts. We intend to seek further sustainable long-term growth by bidding selectively on new revenue-generating projects and acquiring or constructing assets as needed to fulfill such contracts once awarded. We believe this approach facilitates the financing of new vessels based on their anticipated future revenues and ensures that new assets will be employed upon acquisition or completion, which should increase the stability and reliability of cash flows. In pursuing future growth projects, we may enter into joint ventures and partnerships with other reputable companies in the offshore space.
- Project Management and Execution of Growth Projects. We continue to focus on executing on our existing shuttle tanker growth projects delivering between now and 2020, to provide stable cash flows.

Customers

Our customers are predominately global energy producers with whom we have long-term, fixed-rate contracts. Our largest customer measured by annual revenue is Shell, which is a global group of energy and petrochemical companies.

Shell, Petrobras and Equinor accounted for approximately 23%, 18%, and 13% respectively, of our consolidated revenues during 2018. Shell, Petrobras, Equinor and Premier Oil accounted for approximately 31%, 17%, 10% and 10%, respectively, of our consolidated revenues during 2017. Shell, Petrobras and Premier Oil accounted for approximately 30%, 19% and 10%, respectively, of our consolidated revenues during 2016. No other customer accounted for 10% or more of such consolidated revenues during 2018, 2017 or 2016.

Safety, Management of Vessel Operations and Administration
Safety and environmental compliance are our top operational priorities. We operate our vessels in a manner intended to protect the safety and health of our employees, the general public and the environment. We seek to manage the risks inherent in our business and are committed to eliminating incidents that threaten the safety and integrity of our vessels, such as groundings, fires, collisions and petroleum spills. Our Quality Assurance and Training Officers (or QATO) program focuses on conducting rigorous internal audits of our processes and provide our seafarers with on-board training. We have a behavior-based safety program called “Safety in Action” to improve the safety culture in our fleet. We are also committed to reducing our emissions and waste generation. Teekay Corporation's “Operational Leadership, The Journey” is delivered to all employees which sets out the operational expectations, individual responsibilities and commitment to working safely and living Teekay’s vision through a positive and responsible attitude.

Key performance indicators facilitate regular monitoring of our operational performance. Targets are set on an annual basis to drive continuous improvement, and indicators are reviewed monthly to determine if remedial action is necessary to reach the targets.

We assist our operating subsidiaries in managing their ship operations. All vessels are operated under our comprehensive and integrated Safety Management System that complies with the International Management Code for the Safe Operation of Ships and for Pollution Prevention (or ISM Code), the International Standards Organization’s (or ISO) 9001 for Quality Assurance, ISO 14001 for Environment Management Systems, Occupational Health and Safety Assessment Series (or OHSAS) 18001 and the Maritime Labor Convention 2006 (or MLC 2006) that became effective in 2013. The management system is certified by DNV-GL. It has also been separately approved by the Australian flag administrations. Although certification is valid for five years, compliance with the above mentioned standards is confirmed on a yearly basis by a rigorous auditing procedure that includes both internal audits as well as external verification audits by DNV-GL and applicable flag states.

We provide expertise in various functions critical to the operations of our operating subsidiaries. We believe this arrangement affords a safe, efficient and cost-effective operation. Our subsidiaries also provide to us access to human resources, financial and other administrative functions pursuant to administrative services agreements.

Certain of our subsidiaries provide vessel management services to other subsidiaries. These include:

- vessel maintenance (including repairs and dry docking) and certification;
- crewing by competent seafarers;
- procurement of stores, bunkers and spare parts;
- management of emergencies and incidents;
- supervision of shipyard and projects during new-building and conversions;
- insurance; and
- financial management services.

These functions are supported by on-board and on-shore systems for maintenance, inventory, purchasing and budget management. In addition, day-to-day focus on cost control is applied to our operations.

We believe that the generally uniform design of some of our existing vessels and the adoption of common equipment standards provides operational efficiencies, including with respect to crew training and vessel management, equipment operation and repair, and spare parts ordering.
Risk of Loss, Insurance and Risk Management
The operation of any ocean-going vessel carries an inherent risk of catastrophic marine disasters, death or injury of persons and property losses caused by adverse weather conditions, mechanical failures, human error, war, terrorism,

piracy and other circumstances or events. In addition, the transportation of crude oil and petroleum products is subject to the risk of spills and to business interruptions due to political circumstances in foreign countries, hostilities, labor strikes, sanctions and boycotts. The occurrence of any of these events may result in loss of revenues or increased costs.

We carry hull and machinery (marine and war risks) and protection and indemnity insurance coverage to protect against most of the accident-related risks involved in the conduct of our business. Hull and machinery insurance covers loss of or damage to a vessel due to marine perils such as collisions, grounding and weather. Protection and indemnity insurance indemnifies against other liabilities incurred while operating vessels, including injury to the crew, third parties, cargo loss and pollution. The current range of our coverage for third party liability and pollution is $500 million to $1 billion per vessel per incident. We also carry insurance policies covering war risks (including piracy and terrorism).

Under bareboat charters, the customer is responsible to insure the vessel. We believe that current insurance coverage is adequate to protect against most of the accident-related risks involved in the conduct of our business and that we maintain appropriate levels of environmental damage and pollution coverage. However, we cannot assure that all covered risks are adequately insured against, that any particular claim will be paid or that we will be able to procure adequate insurance coverage at commercially reasonable rates in the future. More stringent environmental regulations at times in the past have resulted in increased costs for, and may result in the lack of availability of, insurance against the risks of environmental damage or pollution. All, but three of our vessels, the Petrojarl Knarr FPSO unit, the Itajai FPSO unit and the Libra FPSO unit, are not insured against loss of revenues resulting from vessel off-hire time, based on the cost of this insurance compared to our off-hire experience.

In Norway, the Norwegian Pollution Control Authority requires the installation of VOC emissions reduction units on most shuttle tankers serving the Norwegian continental shelf. Customers bear the cost to install and operate the VOC equipment on board the shuttle tankers.

We have achieved certification under the standards reflected in ISO 9001 for quality assurance, ISO 14001 for environment management systems, OHSAS 18001, and the IMO's International Management Code for the Safe Operation of Ships and Pollution Prevention on a fully integrated basis.

Flag, Classification, Audits and Inspections

Our vessels are registered with reputable flag states, and the hull and machinery of all of our vessels have been "Classed" by one of the major classification societies and members of IACS (International Association of Classification Societies Ltd): DNV-GL, Lloyd's Register of Shipping or American Bureau of Shipping.

The applicable classification society certifies that the vessel's design and build conforms to the applicable class rules and meets the requirements of the applicable rules and regulations of the country of registry of the vessel and the international conventions to which that country is a signatory. The classification society also verifies throughout the vessel's life that it continues to be maintained in accordance with those rules. In order to validate this, the vessels are surveyed by the classification society in accordance with the classification society rules, which in the case of our vessels follows a comprehensive five-year special survey cycle, renewed every fifth year. During each five-year period the vessel undergoes annual and intermediate surveys, the scrutiny and intensity of which is primarily dictated by the age of the vessel. We have enhanced the resiliency of the underwater coatings of each vessel hull and marked the hull to facilitate underwater inspections by divers, their underwater areas are inspected in a dry dock at five year intervals. In-water inspection is carried out during the second or third annual inspection (i.e. during an intermediate survey).

In addition to class surveys, the vessel's flag state also verifies the condition of the vessel during annual flag state inspections, either independently or by additional authorization to class. Also, Port State Authorities of a vessel's port of call are authorized under international conventions to undertake regular and spot checks of vessels visiting their jurisdiction.

Processes followed on board are audited by either the flag state or the classification society acting on behalf of a flag state to ensure that they meet the requirements of the ISM Code. DNV-GL typically carries out this task. We also follow an internal process of internal audits undertaken at each office and vessel annually.

We follow a comprehensive inspections scheme supported by our sea staff, shore-based operational and technical specialists and members of our QATO program. We carry out two internal inspections and one internal audit annually, which helps ensure us that:

- our vessels and operations adhere to our operating standards;
- the structural integrity of the vessel is being maintained;
- machinery and equipment is being maintained to give reliable service;
- we are optimizing performance in terms of speed and fuel consumption; and
- the vessel's appearance will support our brand and meet customer expectations.

Our customers often carry out inspections under the Ship Inspection Report Program (or SIRE Program), which is a significant safety initiative introduced by Oil Companies International Marine Forum (or OCIMF) to specifically address concerns about sub-standard vessels. The inspection results permit charterers to screen a vessel to ensure that it meets their general and specific risk-based shipping requirements.

We believe that the heightened environmental and quality concerns of insurance underwriters, regulators and charterers will generally lead to greater scrutiny, inspection and safety requirements on all vessels in the oil tanker markets and will accelerate the scrapping or phasing out of older vessels throughout these markets.

Overall we believe that our well-maintained and high-quality vessels provide us with a competitive advantage in the current environment of increasing regulation and customer emphasis on quality of service.

Regulations

General

Our business and the operation of our vessels are significantly affected by international conventions and national, state and local laws and regulations in the jurisdictions in which our vessels operate, as well as in the country or countries of their registration. Because these conventions, laws and regulations change frequently, we cannot predict the ultimate cost of compliance or their impact on the resale price or useful life of our vessels. Additional conventions, laws, and regulations may be adopted that could limit our ability to do business or increase the cost of our doing business and that may materially affect our operations. We are required by various governmental and quasi-governmental agencies to obtain permits, licenses and certificates with respect to our operations. Subject to the discussion below and to the fact that the kinds of permits, licenses and certificates required for the operations of the vessels we own will depend on a number of factors, we believe that we will be able to continue to obtain all permits, licenses and certificates material to the conduct of our operations.

International Maritime Organization (or IMO)

The IMO is the United Nations' agency for maritime safety and prevention of pollution. IMO regulations relating to pollution prevention for oil tankers have been adopted by many of the jurisdictions in which our tanker fleet operates. Under IMO regulations and subject to limited exceptions, a tanker must be of double-hull construction in accordance with the requirements set out in these regulations, or be of another approved design ensuring the same level of protection against oil pollution. All of our tankers are double-hulled.

Many countries, but not the United States, have ratified and follow the liability regime adopted by the IMO and set out in the International Convention on Civil Liability for Oil Pollution Damage, 1969, as amended (or CLC). Under this convention, a vessel's registered owner is strictly liable for pollution damage caused in the territorial waters of a contracting state by discharge of persistent oil (e.g. crude oil, fuel oil, heavy diesel oil or lubricating oil), subject to certain defenses. The right to limit liability to specified amounts that are periodically revised is forfeited under the CLC when the spill is caused by the owner's actual fault or when the spill is caused by the owner's intentional or reckless conduct. Vessels trading to contracting states must provide evidence of insurance covering the limited liability of the owner. In jurisdictions where the CLC has not been adopted, various legislative regimes or common law governs, and liability is imposed either on the basis of fault or in a manner similar to the CLC.

IMO regulations also include the International Convention for Safety of Life at Sea (or SOLAS), including amendments to SOLAS implementing the International Ship and Port Facility Security Code (or ISPS), the ISM Code, and the International Convention on Load Lines of 1966. The IMO Marine Safety Committee has also published guidelines for vessels with dynamic positioning (or DP) systems, which would apply to shuttle tankers and DP-assisted FSO units and FPSO units. SOLAS provides rules for the construction of and the equipment required for commercial vessels and includes regulations for their safe operation. Flag states which have ratified the convention and the treaty generally employ the classification societies, which have incorporated SOLAS requirements into their class rules, to undertake surveys to confirm compliance.

SOLAS and other IMO regulations concerning safety, including those relating to treaties on training of shipboard personnel, lifesaving appliances, radio equipment and the global maritime distress and safety system, are applicable to our operations. Non-compliance with IMO regulations, including SOLAS, the ISM Code, ISPS and the specific requirements for shuttle tankers, FSO units and FPSO units under the NPD (Norway) and HSE (United Kingdom) regulations, may subject us to increased liability or penalties, may lead to decreases in available insurance coverage for affected vessels and may result in the denial of access to or detention in some ports. For example, the United States Coast Guard (or Coast Guard) and European Union authorities have indicated that vessels not in compliance with the ISM Code will be prohibited from trading in U.S. and European Union ports.

The ISM Code requires vessel operators to obtain a safety management certification for each vessel they manage, evidencing the shipowner's development and maintenance of an extensive safety management system. Each of the existing vessels in our fleet is currently ISM Code-certified, and we expect to obtain safety management certificates for each newbuilding vessel upon delivery.

With regard to offshore support vessels, such as UMS, SOLAS permits certain exemptions and equivalents to be allowed by the relevant vessel's flag state. The International Code on Intact Stability, 2008 also generally applies to offshore support vessels. The IMO's Maritime Safety Committee (or MSC) has also adopted amendments to the IS Code relating to ships engaged in anchor handling operations and to ships engaged in lifting and towing operations, including escort towing. These amendments are expected to enter into force on January 1, 2020. The IMO has also developed non-mandatory codes and guidelines which apply to various types or aspects of offshore support vessels.

In addition, International Code of Safety for Ships using Gases or other Low-flashpoint Fuels (the IGF Code), which entered into force on January 1, 2017, is mandatory for ships fueled by gases or other low-flashpoint fuels setting out mandatory provisions for the arrangement, installation, control and monitoring of machinery, equipment and systems using low-flashpoint fuel.

Annex VI to the IMO’s International Convention for the Prevention of Pollution from Ships (MARPOL) (or Annex VI) sets limits on sulfur oxide and nitrogen oxide emissions (or NOx) from ship exhausts and prohibits emissions of ozone depleting substances, emissions of volatile compounds from cargo tanks and the incineration of specific substances. Annex VI also includes a world-wide cap on the sulfur content of fuel oil and allows for special "emission control areas" (or ECAs) to be established with more stringent controls on sulfur emissions.

Annex VI also provides for a three-tier reduction in NOx emissions from marine diesel engines, with the final tier (or Tier III) to apply to engines installed on vessels constructed on or after January 1, 2016 and which operate in the North American ECA or the U.S. Caribbean Sea ECA as well as ECAs designated in the future by the IMO. In October 2016, IMO’s Marine Environment Protection Committee (or MEPC) approved the designation of the North Sea and the Baltic Sea as ECAs for NOx emissions; these ECAs and the related amendments to Annex VI of MARPOL (with some exceptions) entered into force on January 1, 2019. Ships constructed on or after January 1, 2021 operating in the North Sea or Baltic Sea must comply with NOx Tier III standards.

Effective January 1, 2020, Annex VI imposes a global limit for sulphur in fuel oil used on board ships of 0.50% m/m (mass by mass), regardless of whether a ship is operating outside a designated ECA. To comply with this new standard, ships may utilize different fuels containing low or zero sulphur (e.g., LNG or biofuels), or utilize exhaust gas cleaning systems, known as “scrubbers”. Amendments to the information to be included in bunker delivery notes relating to the supply of marine fuel oil to ships fitted with alternative mechanisms to address sulphur emission requirements (e.g., scrubbers) became effective January 1, 2019. We have taken and continue to take steps to comply with the 2020 sulphur limit and intend to utilize low or zero sulphur fuel where possible.

As of March 1, 2018, amendments to Annex VI impose new requirements for ships of 5,000 gross tonnage and to collect consumption data for each type of fuel oil they use, as well as certain other data including proxies for transport work.

The IMO has issued guidance regarding protecting against acts of piracy off the coast of Somalia. We comply with these guidelines.

The IMO's Ballast Water Management Convention (BWM Convention) entered into force on September 8, 2017 and stipulates two standards for discharged ballast water. The D-1 standard covers ballast water exchange while the D-2 standard covers ballast water treatment. The BWM Convention requires the implementation of either standard. There will be a transitional period from the entry into force to the International Oil Pollution Prevention (or IOPP) renewal survey in which ballast water exchange can be employed. The MEPC agreed to a compromise on the implementation dates for the D-2 discharge standard: ships constructed on or after September 8, 2017 must comply with the D-2 standard upon delivery. Existing ships should be D-2 compliant on the first IOPP renewal following entry into force if the survey is completed on or after September 8, 2019, or a renewal IOPP survey was completed on or after September 8, 2014 but prior to September 8, 2017. Ships should be D-2 compliant on the second IOPP renewal survey after September 8, 2017 if the first renewal survey after that date is completed prior to September 8, 2019 and if the previous two conditions are not met. Vessels will be required to meet the discharge standard D-2 by installing an approved Ballast Water Management System (or BWMS). Ships sailing in U.S. waters are required to employ a type-approved BWMS which is compliant with USCG regulations. The USCG has approved a number of BWMS.

We estimate that the installation of approved BWMS may cost between $2 million and $3 million per vessel.

MARPOL Annex I also states that oil residue may be discharged directly from the sludge tank to the shore reception facility through standard discharge connections. They may also be discharged to the incinerator or to an auxiliary boiler suitable for burning the oil by means of a dedicated discharge pump. Amendments to Annex I expand on the requirements for discharge connections and piping to ensure residues are properly disposed of. Annex I is applicable for existing vessels with a first renewal survey beginning on or after January 1, 2017.

MSC 91 adopted amendments to SOLAS Regulation II-2/10 to clarify that a minimum of two-way portable radiotelephone apparatus for each fire party for fire-fighter's communication shall be carried on board. These radio devices shall be of explosion proof type or intrinsically safe type. All existing ships (built before July 1, 2014) should comply with this requirement not later than the first safety Equipment survey after July 1, 2018. All new vessels constructed (keel laid) on or after July 1, 2014 must comply with this requirement at the time of delivery. Amendments to SOLAS Regulation II-1/2/-12 on protection against noise, Regulation II-2/1 and II 2/10 on firefighting and new Regulation XI-12-1 on harmonization of survey periods of cargo ships not subject to the ESP code become effective January 1, 2020.

As per MSC. 338(91), requirements have been highlighted for audio and visual indicators for breathing apparatus' which will alert the user before the volume of the air in the cylinder has been reduced to no less than 200 liters. This applies to ships constructed on or after July 1, 2014. Ships constructed before July 1, 2014 must comply no later than July 1, 2019.

The IMO continues to review and introduce new regulations; as such, it is impossible to predict what additional regulations, if any, may be adopted by the IMO and what effect, if any, such regulations might have on our operations.
European Union (or EU)
The EU has adopted legislation that: bans from European waters manifestly sub-standard vessels (defined as vessels that have been detained twice by EU port authorities, in the preceding two years); creates obligations on the part of

EU member port states to inspect minimum percentages of vessels using these ports annually; provides for increased surveillance of vessels posing a high risk to maritime safety or the marine environment; and provides the EU with greater authority and control over classification societies, including the ability to seek to suspend or revoke the authority of negligent societies

The EU has adopted a Directive requiring the use of low sulfur fuel. Since January 1, 2015, vessels have been required to burn fuel with sulfur content not exceeding 0.1% while within EU member states' territorial seas, exclusive economic zones and pollution control zones that are included in "SOx Emission Control Areas." Other jurisdictions have also adopted similar regulations. Since January 1, 2014, the California Air Resources Board has also required vessels to burn fuel with 0.1% sulfur content or less within 24 nautical miles of California. China also has established emission control areas and continues to establish such areas, restricting the maximum sulfur content of the fuel to be used by vessels within those areas and which limits become progressively stricter over time.

IMO regulations required that as of January 1, 2015, all vessels operating within ECAs worldwide recognized under MARPOL Annex VI must comply with 0.1% sulfur requirements. Certain modifications were necessary in order to optimize operation on low sulphur marine gas oil (LSMGO) of equipment originally designed to operate on Heavy Fuel Oil (or HFO). In addition, LSMGO is more expensive than HFO and this could impact the costs of operations. Our exposure to increased cost is in our spot trading vessels, although our competitors bear a similar cost increase as this is a regulatory item applicable to all vessels. All required vessels in our fleet trading to and within regulated low sulfur areas are able to comply with fuel requirements. The global cap on the sulfur content of fuel oil is currently 3.5%, to be reduced to 0.5% by January 1, 2020.

The EU Ship Recycling Regulation aims to prevent, reduce and minimize accidents, injuries and other negative effects on human health and the environment when ships are recycled and the hazardous waste they contain is removed. The legislation applies to all ships flying the flag of an EU country and to vessels with non-EU flags that call at an EU port or anchorage. It sets out responsibilities for ship owners and for recycling facilities both in the EU and in other countries. Each new ship has to have on board an inventory of the hazardous materials (such as asbestos, lead or mercury) it contains in either its structure or equipment. The use of certain hazardous materials is forbidden. Before a ship is recycled, its owner must provide the company carrying out the work with specific information about the vessel and prepare a ship recycling plan. Recycling may only take place at facilities listed on the EU ‘List of facilities’. In 2014, the Council Decision 2014/241/EU authorized EU countries having ships flying their flag or registered under their flag to ratify or to accede to the Hong Kong International Convention for the Safe and Environmentally Sound Recycling of Ships. The Regulation generally entered into force on December 31, 2018, with certain provisions applicable from December 31, 2020. The EU Commission also adopted the a European List of approved ship recycling facilities, as well as four further implementing decisions dealing with certification and other administrative requirements set out in the Regulation.

China

China has also established ECAs in the Pearl River Delta, the Yangtze River Delta and the Bohai Sea area with restrictions limiting sulfur content not to exceed 0.5% in such ECAs, with such limit decreasing over time.

All the key ports within the three China ECAs (i.e. Tianjin, Qinhuangdao, Tangshan, Huanghua, Shenzhen, Guangzhou, Zhuhai, Shanghai, Ningbo-Zhoushan, Suzhou and Nantong) have implemented the low sulfur bunker requirements.

Commencing January 1, 2018, ships berthing (excluding one hour after berthing and one hour before departure) at all ports within the China ECAs are required to use fuel with sulfur contents at or below 0.5%. These limitations apply to the entire period vessels are in port within China ECAs and became effective January 1, 2019.

China will complete an assessment of the effectiveness of the introduced measures by the end of 2019. Based on the results of such assessment possible further enforcement of regulations limiting SOx emission in ECAs may be implemented reducing the sulfur content to 0.1% for ships in the ECA, extending the boundaries of the ECAs or introducing new control measures.

North Sea, Canada and Brazil

Our shuttle tankers and FPSO units primarily operate in the North Sea, Brazil and Newfoundland, Canada.

There is no international regime in force which deals with compensation for oil pollution from offshore craft, such as FPSO units. Whether the CLC and the International Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage 1971, as amended by the 1992 Protocol (or the Fund Convention), which deal with liability and compensation for oil pollution, and the Convention on Limitation of Liability for Maritime Claims 1976, as amended by the 1996 Protocol (or the 1976 Limitation of Liability Convention), which deals with limitation of liability for maritime claims, apply to FPSO units is neither straightforward nor certain. This is due to the definition of “ship” under these conventions and the requirement that oil is “carried” on board the relevant vessel. Nevertheless, the wording of the 1992 Protocol to the CLC leaves room for arguing that FPSO units and oil pollution caused by them can come under the ambit of these conventions for the purposes of liability and compensation. However, the application of these conventions also depends on their implementation by the relevant domestic laws of the countries which are parties to them.

UK’s Merchant Shipping Act 1995, as amended (or the MSA), implements the CLC but uses a wider definition of a “ship” than the one used in the CLC and in its 1992 Protocol but still refers to the criteria used by the CLC. It is therefore doubtful that FPSO units fall within its wording. However, the MSA also includes separate provisions for liability for oil pollution. These apply to vessels which fall within a much wider definition and include non-seagoing vessels. It is arguable that the wording of these MSA provisions is wide enough to cover oil pollution caused by offshore crafts such as FPSO units. The liability regime under these MSA provisions is similar to that imposed under the CLC but limitation of liability is subject to the 1976 Limitation of Liability Convention regime (as implemented in the MSA),

With regard to the 1976 Limitation of Liability Convention, it is, again, doubtful whether it applies to FPSO units, as it contains certain exceptions in relation to vessels constructed for or adapted to and engaged in drilling and in relation to floating platforms constructed for the purpose of exploring or exploiting natural resources of the seabed or its subsoil. However, these exceptions are not included in the legislation implementing the 1976 Limitation of Liability

Convention in the UK, which is also to be found in the MSA. In addition, the MSA sets out a very wide definition of “ship” in relation to which the 1976 Limitation of Liability Convention is to apply and there is room for argument that if FPSO units fall within that definition of “ship”, they are subject in the UK to the limitation provisions of the 1976 Limitation of Liability Convention.

In the absence of an international regime regulating liability and compensation for oil pollution caused by offshore oil and gas facilities, the Offshore Pollution Liability Agreement 1974 was entered into by a number of oil companies and became effective in 1975. This is a voluntary industry oil pollution compensation scheme which is funded by the parties to it. These are operators or intending operators of offshore facilities used in the exploration for and production of oil and gas located within the jurisdictions of a number of “Designated States” which include the UK, Denmark, Norway, Germany, France, Greenland, Ireland, the Netherlands, the Isle of Man and the Faroe Islands. The scheme provides for strict liability of the relevant operator for pollution damage and remedial costs, subject to a limit, and the operators must provide evidence of financial responsibility in the form of insurance or other security to meet the liability under the scheme.

With regard to FPSO units, Chapter 7 of Annex I of MARPOL (which contains regulations for the prevention of oil pollution) sets out special requirements for fixed and floating platforms, including, amongst others, FPSO units and FSUs. The IMO’s Marine Environment Protection Committee has issued guidelines for the application of MARPOL Annex I requirements to FPSO units and FSUs.

The EU’s Directive 2004/35/CE on environmental liability with regard to the prevention and remedying of environmental damage (or the Environmental Liability Directive) deals with liability for environmental damage on the basis of the “polluter pays” principle. Environmental damage includes damage to protected species and natural habitats and damage to water and land. Under this Directive, operators whose activities caused the environmental damage or the imminent threat of such damage are to be held liable for the damage (subject to certain exceptions). With regard to environmental damage caused by specific activities listed in the Directive, operators are strictly liable. This is without prejudice to their right to limit their liability in accordance with national legislation implementing the 1976 Limitation of Liability Convention. The Directive applies both to damage which has already occurred and where there is an imminent threat of damage. It also requires the relevant operator to take preventive action, to report an imminent threat and any environmental damage to the regulators and to perform remedial measures, such as clean-up. The Environmental Liability Directive is implemented in the UK by the Environmental Damage (Prevention and Remediation) Regulations 2015.

In June 2013 the EU adopted Directive 2013/30/EU on safety of offshore oil and gas operations and amending Directive 2004/35/EC (or the Offshore Safety Directive). This Directive lays down minimum requirements for member states and the European Maritime Safety Agency for the purposes of reducing the occurrence of major accidents related to offshore oil and gas operations, thus increasing protection of the marine environment and coastal economies against pollution, establishing minimum conditions for safe offshore exploration and exploitation of oil and gas, and limiting disruptions to the EU's energy production and improving responses to accidents. The Offshore Safety Directive sets out extensive requirements, such as preparation of a major hazard report with risk assessment, emergency response plan and safety and environmental management system applicable to the relevant oil and gas installation before the planned commencement of the operations, independent verification of safety and environmental critical elements identified in the risk assessment for the relevant oil and gas installation, and ensuring that factors such as the applicant's safety and environmental performance and its financial capabilities or security to meet potential liabilities arising from the oil and gas operations are taken into account when considering granting a license. Under the Offshore Safety Directive, Member States are to ensure that the relevant licensee is financially liable for the prevention and remediation of environmental damage (as defined in the Environmental Liability Directive) caused by offshore oil and gas operations carried out by or on behalf of the licensee or the operator. Member States must lay down rules on penalties applicable to infringements of the legislation adopted pursuant to this Directive. Member States were required to bring into force laws, regulations and administrative provisions necessary to comply with this Directive by 19 July 2015. The Offshore Safety Directive has been implemented in the UK by a number of different UK Regulations, including the Environmental Damage (Prevention and Remediation) (England) Regulations 2015, as amended, (which revoked and replaced the Environmental Damage (Prevention and Remediation) Regulations 2015)) and the Offshore Installations (Offshore Safety Directive)(Safety Case etc.) Regulations 2015, as amended, both of which were effective from July 19, 2015.

In addition to the regulations imposed by the IMO and EU, countries having jurisdiction over North Sea areas impose regulatory requirements in connection with operations in those areas, including the United Kingdom and Norway. In the UK, the exploration for and production of oil and gas in the UK, including the UK sector of the North Sea is undertaken pursuant to the Petroleum Act 1998 in accordance with the conditions of a license issued by the UK government. Model clauses included in such licenses require licensees amongst other things to operate in accordance with methods customarily used in good oilfield practice and to take all steps practicable to prevent the escape of oil. Various UK regulations dealing with environmental and other aspects of offshore oil and gas activities are also in place. These regulatory requirements, together with additional requirements imposed by operators in North Sea oil fields, require that we make further expenditures for sophisticated equipment, reporting and redundancy systems on the shuttle tankers and for the training of seagoing staff. Additional regulations and requirements may be adopted or imposed that could limit our ability to do business or further increase the cost of doing business in the North Sea.

In Norway, the Norwegian Pollution Control Authority requires the installation of Volatile Organic Compound (or VOC) emissions reduction units on most shuttle tankers serving the Norwegian continental shelf. Customers bear the cost to install and operate the VOC equipment on board the shuttle tankers.

In addition to the requirements of major IMO shipping conventions, the exploration for and production of oil and gas within the Newfoundland & Labrador (or NL) offshore area is conducted pursuant to the Canada Newfoundland and

Labrador Atlantic Accord Implementation Act (or the Accord Act) in accordance with the conditions of a license and authorization issued by the Canada-Newfoundland and Labrador Offshore Petroleum Board (or CNLOPB). Various regulations dealing with environmental, occupational health and safety, and other aspects of offshore oil and gas activities have been enacted under the Accord Act. The CNLOPB has also issued interpretive guidelines concerning compliance with the regulations, and compliance with CNLOPB guidelines may be a condition of the issuance or renewal of the license and authorizations. These regulations and guidelines require that the shuttle tankers in the NL offshore area meet stringent standards for equipment, reporting and redundancy systems, and for the training and equipping of seagoing staff. Further, licensees are required by the Accord Act to provide a benefits plan satisfactory to CNLOPB. Such plans generally require the licensee to: establish an office in NL; give NL residents first consideration for training and employment; make expenditures for research and development and education and training to be carried out in NL; and give first consideration to services provided from within NL and to goods manufactured in NL. These regulatory requirements may change as regulations and CNLOPB guidelines are amended or replaced from time to time.

In addition to the regulations imposed by the IMO, Brazil imposes regulatory requirements in connection with operations in its territory, including specific requirements for the operations of vessels flagged in countries other than Brazil. Brazil has several maritime regulations and frequent amendments and updates. Firstly, with respect to environmental protection while operating under Brazilian waters, the Federal Constitution establishes that the State shall regulate and impose protections to the environment, establishing liability in the civil, administrative and criminal spheres. Law no. 6938/1981 sets the National Environmental Policy and Law no. 9966/2000, known as “The Oil Law”, institutes several rules, liabilities and penalties regarding the handling of oil or other dangerous substances, being applicable to foreign vessels and platforms operating in Brazilian waters. Regulating the exploitation and production of oil and natural gas, Law no. 9.478/1997, known as “The Petroleum Law”, created the National Petroleum Agency (or ANP), responsible for regulating and supervising the industry through directives and resolutions. After the discovery of the pre-salt, the mentioned law was altered in some points by Law no. 12.351/2010 and Laws 13.303/2016 and 13.609/2018, being the industry also regulated by several administrative Regulations issued by the ANP. ANP is currently reviewing an amendment to its Ordinance 170/02, with aims to specifically regulate ship-to-ship operations in addition to the transportation of hydrocarbons and byproducts.

Additional requirements and restrictions for the operation of offshore vessels and shuttle tankers are imposed by Law 9.432/97 and by the National Waterway Transport Agency ("ANTAQ"), instituted by Law 10.233/2001, by way of frequently updated administrative resolutions. The transit of vessels and permanence and operation of offshore units in Brazil are further regulated by the Maritime Authorities, through law and administrative Ordinances known as "NORMAM". Brazil also is a signatory of several IMO/MARPOL conventions, including the deliberation to reduce Sulphur emissions as of January 1st, 2020, agreed during the 70º session of the Marine Environment Protection Committee, held at IMO's headquarters on June 2016. Under Brazil's environmental laws, owners and operators of vessels are strictly liable for damages to the environment. Other penalties for non-compliance with environmental laws include fines, loss of tax incentives and suspension of activities. Operators such as Petrobras may impose additional requirements, such as compliance with specific health, safety and environmental standards or the use of local labor. Additional regulations and requirements may be adopted or imposed that could limit our ability to do business or further increase the cost of doing business in Brazil.

United States

The United States has enacted an extensive regulatory and liability regime for the protection and cleanup of the environment from oil spills, including discharges of oil cargoes, bunker fuels or lubricants, primarily through the Oil Pollution Act of 1990 (or OPA 90) and the Comprehensive Environmental Response, Compensation and Liability Act (or CERCLA). OPA 90 affects all owners, bareboat charterers, and operators whose vessels trade to the United States or its territories or possessions or whose vessels operate in United States waters, which include the U.S. territorial sea and 200-mile exclusive economic zone around the United States. CERCLA applies to the discharge of "hazardous substances" rather than "oil" and imposes strict joint and several liabilities upon the owners, operators or bareboat charterers of vessels for cleanup costs and damages arising from discharges of hazardous substances. We believe that petroleum products should not be considered hazardous substances under CERCLA, but additives to oil or lubricants used on vessels might fall within its scope.

Under OPA 90, vessel owners, operators and bareboat charterers are "responsible parties" and are jointly, severally and strictly liable (unless the oil spill results solely from the act or omission of a third party, an act of God or an act of war and the responsible party reports the incident and reasonably cooperates with the appropriate authorities) for all containment and cleanup costs and other damages arising from discharges or threatened discharges of oil from their vessels. These other damages are defined broadly to include:

- natural resources damages and the related assessment costs;
- real and personal property damages;
- net loss of taxes, royalties, rents, fees and other lost revenues;
- lost profits or impairment of earning capacity due to property or natural resources damage;
- net cost of public services necessitated by a spill response, such as protection from fire, safety or health hazards; and
- loss of subsistence use of natural resources.

OPA 90 limits the liability of responsible parties in an amount it periodically updates. The liability limits do not apply if the incident was proximately caused by violation of applicable U.S. federal safety, construction or operating regulations, including IMO conventions to which the United States is a signatory, or by the responsible party's gross negligence or willful misconduct, or if the responsible party fails or refuses to report the incident or to cooperate and assist in connection with the oil removal activities. Liability under CERCLA is also subject to limits unless the incident is caused by gross negligence, willful misconduct or a violation of certain regulations. We currently maintain for each of our vessels pollution liability coverage in the maximum coverage amount of $1 billion per incident. A catastrophic spill could exceed the coverage available, which could harm our business, financial condition and results of operations.

Under OPA 90, with limited exceptions, all newly built or converted tankers delivered after January 1, 1994 and operating in U.S. waters must be double-hulled. All of our tankers are double-hulled.

OPA 90 also requires owners and operators of vessels to establish and maintain with the Coast Guard evidence of financial responsibility in an amount at least equal to the relevant limitation amount for such vessels under the statute. The Coast Guard has implemented regulations requiring that an owner or operator of a fleet of vessels must demonstrate evidence of financial responsibility in an amount sufficient to cover the vessel in the fleet having the greatest maximum limited liability under OPA 90 and CERCLA. Evidence of financial responsibility may be demonstrated by insurance, surety bond, self-insurance, guaranty or an alternate method subject to approval by the Coast Guard. Under the self-insurance provisions, the ship owners or operators must have a net worth and working capital, measured in assets located in the United States against liabilities located anywhere in the world, that exceeds the applicable amount of financial responsibility. We have complied with the Coast Guard regulations by using self-insurance for certain vessels and obtaining financial guarantees from a third party for the remaining vessels. If other vessels in our fleet trade into the United States in the future, we expect to obtain guarantees from third-party insurers.

OPA 90 and CERCLA permit individual U.S. states to impose their own liability regimes with regard to oil or hazardous substance pollution incidents occurring within their boundaries, and some states have enacted legislation providing for unlimited strict liability for spills. Several coastal states, such as California, Washington and Alaska require state-specific evidence of financial responsibility and vessel response plans. We intend to comply with all applicable state regulations in the ports where our vessels call.

Owners or operators of vessels, including tankers operating in U.S. waters are required to file vessel response plans with the Coast Guard, and their tankers are required to operate in compliance with their Coast Guard approved plans. Such response plans must, among other things:

- address a “worst case” scenario and identify and ensure, through contract or other approved means, the availability of necessary private response resources to respond to a “worst case discharge”;
- describe crew training and drills; and
- identify a qualified individual with full authority to implement removal actions.

We have filed vessel response plans with the Coast Guard and have received its approval of such plans. In addition, we conduct regular oil spill response drills in accordance with the guidelines set out in OPA 90. The Coast Guard has announced it intends to propose similar regulations requiring certain vessels to prepare response plans for the release of hazardous substances.

OPA 90 and CERCLA do not preclude claimants from seeking damages resulting from the discharge of oil and hazardous substances under other applicable law, including maritime tort law. The application of this doctrine varies by jurisdiction.

The United States Clean Water Act also prohibits the discharge of oil or hazardous substances in U.S. navigable waters and imposes strict liability in the form of penalties for unauthorized discharges. The Clean Water Act imposes substantial liability for the costs of removal, remediation and damages and complements the remedies available under OPA 90 and CERCLA discussed above.

Our vessels that discharge certain effluents, including ballast water, in U.S. waters must obtain a Clean Water Act (or CWA) permit from the Environmental Protection Agency (or EPA) titled the “Vessel General Permit” and comply with a range of effluent limitations, best management practices, reporting, inspections and other requirements. The Vessel General Permit incorporated Coast Guard requirements for ballast water exchange and includes specific technology-based requirements for vessels, and includes an implementation schedule to require vessels to meet the ballast water effluent limitations by the first dry docking after January 1, 2016. This permit is effective to December 18, 2018. The Vessel Incidental Discharge Act (or VIDA) was signed into law on December 4, 2018, and establishes a new framework for the regulation of vessel incidental discharges under the CWA. VIDA requires the EPA to develop performance standards for incidental discharges, and requires the Coast Guard to develop regulations within two years of the EPA’s promulgation of standards. Under VIDA, all provisions of the Vessel General Permit remain in force and effect as currently written until the Coast Guard regulations are finalized.

Vessels that are constructed after December 1, 2013 are subject to the ballast water numeric effluent limitations. Several U.S. states have added specific requirements to the Vessel General Permit and, in some cases, may require vessels to install ballast water treatment technology to meet biological performance standards.

California Biofouling Management Plan requirements are as follows: developing and maintaining a Biofouling Management Plan, developing and maintaining a Biofouling Record Book, mandatory biofouling management of the vessel’s wetted surfaces, mandatory biofouling management for vessels that undergo an extended residency period (i.e. remain in the same location for 45 or more days). All vessel calling at California water were required to submit the "Annual Marine Invasive Reporting Form" by October 1, 2017 and should have CA-Biofouling management plan after a vessel’s first regularly scheduled out-of-water maintenance (i.e. dry dock) after January 1, 2018, or upon delivery on or after January 1, 2018.

New Zealand

New Zealand's Craft Risk Management Standard (or CRMS) requirements are based on the IMO's guidelines for the control and management of ships' biofouling to minimize the transfer of invasive aquatic species.

Marine pests and diseases brought in on vessel hulls (biofouling) are a threat to New Zealand's marine resources. From May 15, 2018, all vessels arriving in New Zealand will need to have a clean hull. Vessels staying up to 20 days and only visiting designated ports (places of first arrival) will be allowed a slight amount of biofouling. Vessels

staying longer and visiting other places will only be allowed a slime layer and goose barnacles.
Greenhouse Gas Regulation
In February 2005, the Kyoto Protocol to the United Nations Framework Convention on Climate Change (or the Kyoto Protocol) entered into force. Pursuant to the Kyoto Protocol, adopting countries are required to implement national programs to reduce emissions of greenhouse gases. In December 2009, more than 27 nations, including the United States, entered into the Copenhagen Accord. The Copenhagen Accord is non-binding, but is intended to pave the way for a comprehensive, international treaty on climate change. In December 2015, the Paris Agreement (or the Paris Agreement) was adopted by a large number of countries at the 21st Session of the Conference of Parties (commonly known as COP 21, a conference of the countries which are parties to the United Nations Framework Convention on Climate Change; the COP is the highest decision-making authority of this organization). The Paris Agreement, which entered into force on November 4, 2016, deals with greenhouse gas emission reduction measures and targets from 2020 in order to limit the global temperature increases to well below 2° Celsius above pre-industrial levels. Although shipping was ultimately not included in the Paris Agreement, it is expected that the adoption of the Paris Agreement may lead to regulatory changes in relation to curbing greenhouse gas emissions from shipping.

IMO adopted regulations imposing technical and operational measures for the reduction of greenhouse gas emissions became effective in January 2013. In October 2016, the IMO adopted a mandatory data collection system under which vessels of 5,000 gross tonnages and above are to collect fuel consumption and other data and to report the aggregated data so collected to their flag state at the end of each calendar year. The new requirements entered into force on March 1, 2018. The IMO also approved a roadmap for the development of a comprehensive IMO strategy on reduction of greenhouse gas emissions from ships with an initial strategy adopted on April 13, 2018 and a revised strategy to be adopted in 2023.

The EU also has indicated that it intends to propose an expansion of an existing EU emissions trading regime to include emissions of greenhouse gases from vessels, and individual countries in the EU may impose additional requirements. The EU has adopted regulations on the monitoring, reporting and verification (or MRV) of CO2 emissions from vessels (or the MRV Regulation), which entered into force on July 1, 2015. The MRV Regulation aims to quantify and reduce CO2 emissions from shipping and generally requires ship owners and operators to annually monitor, report and verify CO2 emissions for vessels larger than 5,000 gross tonnage calling at any EU and EFTA (Norway and Iceland) port. Data collection takes place on a per voyage basis and started January 1, 2018. The reported CO2 emissions, together with additional data, such as cargo and energy efficiency parameters, are to be verified by independent verifiers and sent to a central database, managed by the European Maritime Safety Agency. To comply with the MRV Regulation, we have prepared an EU MRV monitoring plan and EU MRV monitoring template in line with legislative requirement. While the EU was considering a proposal for the inclusion of shipping in the EU Emissions Trading System as from 2021 (in the absence of a comparable system operating under the IMO), it appears that the decision to include shipping may be deferred until 2023.

In parallel to the EU MRV Regulation, the IMO has introduced a three-step approach, based on collecting and analyzing fuel consumption data, before agreeing what further actions may be required to reduce greenhouse gas emissions from ships. The IMO data collection system came into effect in March 2018.

In the United States, the EPA issued an "endangerment finding" regarding greenhouse gases under the Clean Air Act. While this finding in itself does not impose any requirements on our industry, it authorizes the EPA to regulate directly greenhouse gas emissions through a rule-making process. In addition, climate change initiatives are being considered in the United States Congress and by individual states. Any passage of new climate control legislation or other regulatory initiatives by the IMO, the EU, the United States or other countries or states where we operate that restrict emissions of greenhouse gases could have a significant financial and operational impact on our business that we cannot predict with certainty at this time.

Vessel Security

The ISPS was adopted by the IMO in December 2002 in the wake of heightened concern over worldwide terrorism and became effective on July 1, 2004. The objective of ISPS is to enhance maritime security by detecting security threats to ships and ports and by requiring the development of security plans and other measures designed to prevent such threats. Each of the existing vessels in our fleet currently complies with the requirements of ISPS and Maritime Transportation Security Act of 2002 (U.S. specific requirements). Procedures are in place to inform the relevant reporting regimes such as Maritime Security Council Horn of Africa (or MSCHOA), the Maritime Domain Awareness for Trade - Gulf of Guinea (or MDAT-GoG), the Information Fusion Center (or IFC) whenever our vessels are calling in the Indian Ocean Region, or West Coast of Africa (or WAC) or SE Asia high risk areas respectively. In order to mitigate the security risk, security arrangements are required for vessels which travel through these high risk areas.

C. Organizational Structure

Our sole general partner is Teekay Offshore GP L.L.C., in which, as at December 31, 2018, Brookfield held 51% of the general partner interest, and a subsidiary of Teekay Corporation held 49% of the general partner interest.

Please read Exhibit 8.1 to this Annual Report for a list of our significant subsidiaries as of December 31, 2018.

D. Properties

Other than our vessels and VOC plants mentioned above, we do not have any material property.

E. Taxation of the Partnership

United States Taxation

The following is a discussion of the expected material U.S. federal income tax considerations applicable to us. This discussion is based upon the provisions of the Code, legislative history, applicable U.S. Treasury Regulations (or Treasury Regulations), judicial authority and administrative interpretations, all as in effect on the date of this Annual Report, and which are subject to change, possibly with retroactive effect, or are subject to different interpretations.

Changes in these authorities may cause the tax consequences to vary substantially from the consequences described below.

Election to be Taxed as a Corporation. We have elected to be taxed as a corporation for U.S. federal income tax purposes. As such, we are subject to U.S. federal income tax on our income to the extent it is from U.S. sources or otherwise is effectively connected with the conduct of a trade or business in the United States as discussed below.

Taxation of Operating Income. A significant portion of our gross income will be attributable to the transportation of crude oil and related products. For this purpose, gross income attributable to transportation (or Transportation Income) includes income derived from, or in connection with, the use (or hiring or leasing for use) of a vessel to transport cargo, or the performance of services directly related to the use of any vessel to transport cargo, and thus includes income from time charters, contracts of affreightment, bareboat charters, and voyage charters.

Fifty percent (50%) of Transportation Income that either begins or ends, but that does not both begin and end, in the United States (or U.S. Source International Transportation Income) is considered to be derived from sources within the United States. Transportation Income that both begins and ends in the United States (or U.S. Source Domestic Transportation Income) is considered to be 100% derived from sources within the United States. Transportation Income exclusively between non-U.S. destinations is considered to be 100% derived from sources outside the United States. Transportation Income derived from sources outside the United States generally is not subject to U.S. federal income tax.

Based on our current operations, a substantial portion of our Transportation Income is from sources outside the United States and not subject to U.S. federal income tax. However, certain of our activities give rise to U.S. Source International Transportation Income. Unless the exemption from U.S. taxation under Section 883 of the Code (or the Section 883 Exemption) applies, our U.S. Source International Transportation Income generally is subject to U.S. federal income taxation under either the net basis and branch profits taxes or the 4% gross basis tax, each of which is discussed below.

The Section 883 Exemption. In general, the Section 883 Exemption provides that if a non-U.S. corporation satisfies the requirements of Section 883 of the Code and the Treasury Regulations thereunder (or the Section 883 Regulations), it will not be subject to the net basis and branch profits taxes or the 4% gross basis tax described below on its U.S. Source International Transportation Income. The Section 883 Exemption does not apply to U.S. Source Domestic Transportation Income.

A non-U.S. corporation will qualify for the Section 883 Exemption if, among other things, it (i) is organized in a jurisdiction outside the United States that grants an exemption from tax to U.S. corporations on international Transportation Income (or an Equivalent Exemption), (ii) meets one of three ownership tests (or Ownership Tests) described in the Section 883 Regulations, and (iii) meets certain substantiation, reporting and other requirements (or the Substantiation Requirements).

We are organized under the laws of the Republic of the Marshall Islands. The U.S. Treasury Department has recognized the Republic of the Marshall Islands as a jurisdiction that grants an Equivalent Exemption. We also believe that we will be able to satisfy the Substantiation Requirements. However, we do not believe that we meet the Ownership Tests and therefore we will not qualify for the Section 883 Exemption and our U.S. Source International Transportation Income will not be exempt from U.S. federal income taxation.

Net Basis Tax and Branch Profits Tax. If the Section 883 Exemption does not apply, our U.S. Source International Transportation Income may be treated as effectively connected with the conduct of a trade or business in the United States (or Effectively Connected Income) if we have a fixed place of business in the United States and substantially all of our U.S. Source International Transportation Income is attributable to regularly scheduled transportation or, in the case of income derived from bareboat charters, is attributable to a fixed place of business in the United States. Based on our current operations, none of our potential U.S. Source International Transportation Income is attributable to regularly scheduled transportation or is derived from bareboat charters attributable to a fixed place of business in the United States. As a result, we do not anticipate that any of our U.S. Source International Transportation Income will be treated as Effectively Connected Income. However, there is no assurance that we will not earn income pursuant to regularly scheduled transportation or bareboat charters attributable to a fixed place of business in the United States in the future, which would result in such income being treated as Effectively Connected Income. U.S. Source Domestic Transportation Income generally will be treated as Effectively Connected Income.

Any income we earn that is treated as Effectively Connected Income would be subject to U.S. federal corporate income tax (the highest statutory rate for 2018 onwards is 21%) and a 30% branch profits tax imposed under Section

884 of the Code. In addition, a branch interest tax could be imposed on certain interest paid or deemed paid by us.

On the sale of a vessel that has produced Effectively Connected Income, we generally would be subject to the net basis and branch profits taxes with respect to our gain recognized up to the amount of certain prior deductions for depreciation that reduced Effectively Connected Income. Otherwise, we would not be subject to U.S. federal income tax with respect to gain realized on the sale of a vessel, provided the sale is considered to occur outside of the United States under U.S. federal income tax principles.

The 4% Gross Basis Tax. If the Section 883 Exemption does not apply and we are not subject to the net basis and branch profits taxes described above, we will be subject to a 4% U.S. federal income tax on our gross U.S. Source International Transportation Income, without benefit of deductions. For 2019, we do not expect that the U.S. federal income tax on such U.S. Source International Transportation Income will be material based on the amount of U.S. Source International Transportation Income we earned for 2018. The amount of such tax for which we are liable in any year will depend upon the amount of income we earn from voyages into or out of the United States in such year, however, which is not within our complete control.

Marshall Islands Taxation

Because we and our controlled affiliates do not, and we do not expect that we and our controlled affiliates will, conduct business, operations, or transactions in the Republic of the Marshall Islands, neither we nor our controlled affiliates are subject to income, capital gains, profits or other taxation under current Marshall Islands law, other than taxes, fines, or fees due to (i) the incorporation, dissolution, continued existence, merger, domestication (or similar concepts) of legal entities registered in the Republic of the Marshall Islands, (ii) filing certificates (such as certificates of incumbency, merger, or redomiciliation) with the Marshall Islands registrar, (iii) obtaining certificates of good standing from, or certified copies of documents filed with, the Marshall Islands registrar, (iv) compliance with Marshall Islands law concerning vessel ownership, such as tonnage tax, or (v) non-compliance with requests made by the Marshall Islands registrar of corporations relating to our books and records and the books and records of our subsidiaries. As a result, distributions by controlled affiliates to us are not subject to Marshall Islands taxation.

Other Taxation
We and our subsidiaries are subject to taxation in certain non-U.S. jurisdictions because we or our subsidiaries are either organized, or conduct business or operations, in such jurisdictions, but we do not expect any such tax to be material. However, we cannot assure this result as tax laws in these or other jurisdictions may change or we may enter into new business transactions relating to such jurisdictions, which could affect our tax liability. Please read Item 18 – Financial Statements: Note 13 – Income Taxes.
Item 4A. Unresolved Staff Comments
Not applicable.
Item 5. Operating and Financial Review and Prospects
The following discussion should be read in conjunction with the financial statements and notes thereto. Please read Item 18 - Financial Statements.
Management's Discussion and Analysis of Financial Conditions and Results of Operations
OVERVIEW
We are a leading international midstream services provider to the offshore oil production industry, focused on the ownership and operation of critical infrastructure assets in offshore oil regions of the North Sea, Brazil and the East Coast of Canada. We were formed as a Republic of the Marshall Islands limited partnership in August 2006 by Teekay Corporation (NYSE: TK), a portfolio manager and project developer in the marine midstream market. In September 2017, affiliates of Brookfield Business Partners L.P. (NYSE: BBU) (TSX: BBU.UN) (or Brookfield) purchased from an affiliate of Teekay Corporation a 49% interest in our general partner and purchased approximately 60% of our common units and certain warrants to purchase additional common units from us. In early-July 2018, Brookfield, through an affiliate, exercised its option to acquire an additional 2% interest in our general partner from an affiliate of Teekay Corporation. These transactions were part of a comprehensive solution intended for us to strengthen our balance sheet and fully fund our existing growth projects. We seek to leverage the expertise, relationships and reputations of Brookfield and Teekay Corporation to pursue long-term growth opportunities.

We operate shuttle tankers, FPSO units, FSO units, a UMS, long-distance towage and offshore installation vessels and conventional crude oil tankers. As at December 31, 2018, our fleet consisted of 35 shuttle tankers (including six newbuildings which are scheduled for delivery in late-2019 through 2021, two chartered-in vessels and one HiLoad Dynamic Positioning (or HiLoad DP) unit), eight FPSO units, six FSO units, ten long-distance towage and offshore installation vessels, one UMS and two chartered-in conventional oil tankers, in which our interests range from 50% to 100%.

Our near-to-medium term business strategy is primarily to focus on extending contracts and re-deploying existing assets on long-term charters, repaying or refinancing scheduled debt obligations and pursuing additional growth projects. Despite the weakness in the global energy and capital markets, our operating cash flows prior to changes in non-cash working capital items relating to operating activities remain stable, supported by a large and well-diversified portfolio of fee-based contracts, which primarily consist of medium-to-long-term contracts with high quality counterparties.

Although global crude oil and gas prices have experienced moderate recovery since falling from the highs of mid-2014, prices have not returned to those same highs and remain volatile due to global and regional geopolitical, economic and strategic risks and changes. This has affected the energy and capital markets and may also result in our vessels being employed on customer contracts that are cancellable or the failure of customers to exercise charter extension options, potentially resulting in increased off-hire for affected vessels. Conversely, we expect that a continuation of lower oil prices will motivate charterers to use existing FPSO units on new projects, given their lower cost relative to a newbuilding unit. Our operational focus over the short-term is to focus on extending contracts and the redeployment of our assets that are scheduled to come off charter over the next few years.

Our long-term growth strategy focuses on expanding our fleet of shuttle tankers and FPSO units under medium-to-long term charter contracts. Over the long-term, we intend to continue our practice of primarily acquiring vessels as needed for approved projects only after the long-term charters for the projects have been awarded to us, rather than ordering vessels on a speculative basis. We have entered and may enter into joint ventures and partnerships with companies that may provide increased access to such charter opportunities or may engage in vessel or business acquisitions. We seek to leverage the expertise, relationships and reputation of Brookfield and Teekay Corporation to pursue these growth opportunities in the offshore sectors and may consider other opportunities to which our competitive strengths are well suited. Our operating fleet primarily trades on medium to long-term, stable contracts.

SIGNIFICANT DEVELOPMENTS

Change in Control

In July 2018, Brookfield, through an affiliate, exercised its option to acquire an additional 2% of ownership interest in our general partner from an affiliate of Teekay Corporation in exchange for 1.0 million warrants, with each warrant exercisable for one of our common units. After exercising this option, Brookfield holds 51% of the general partner interest and may elect a majority of the members of our general partner's board of directors. Teekay Corporation will continue to have the right to appoint two members of the board of directors so long as it owns at least 10% of our outstanding common units.

Brookfield’s exercise of this option represented a change of control event with respect to (1) our $300.0 million five-year senior unsecured bonds that mature in July 2019, which entitled each holder of such bonds to require us to repurchase any or all of the bonds held by such holder for a price equal to 101% of the principal amount of such repurchased bonds plus any accrued and unpaid interest, and (2) our Norwegian Krone (or NOK) 1,000 million senior unsecured bonds that matured in January 2019, which entitled each holder of such bonds to require us to repurchase the bonds held by such holder for a price equal to 100% of the principal amount of such repurchased bonds plus accrued and unpaid interest.

Vessel Deliveries

Petrojarl I FPSO Unit Charter Commencement

In May 2018, the Petrojarl I FPSO unit successfully achieved first oil and commenced its five-year charter contract with a consortium led by Queiroz Galvão Exploração e Produção SA (or QGEP) on the Atlanta oil field. The Petrojarl I FPSO unit operates under a charter rate profile with a lower day rate during the first 18 months of production. During the final three and a half years of the contract, the charter contract will increase to a higher day rate. The charter contract also contains an oil price and oil production tariff.

Delivery of East Coast of Canada Shuttle Tanker Newbuildings

In March 2018, we took delivery of the last of the three East Coast of Canada shuttle tanker newbuildings, the Dorset Spirit, which commenced operations in May 2018 on a 15-year charter contract (of which 12 years remain), plus extension options, with a group of oil companies. The Dorset Spirit replaced an existing owned vessel servicing the East Coast of Canada, which existing vessel was repositioned to the North Sea to operate in our CoA fleet.

Delivery of Towage Newbuilding

In February 2018, we took delivery of the last of four state-of-the-art SX-157 Ulstein Design ultra-long distance towage and offshore installation newbuildings, the ALP Keeper, constructed by Niigata Shipbuilding & Repair in Japan. Due to the delayed delivery of the vessel, we received damages from the shipyard of $7.7 million during the second quarter of 2017.

FPSO Contracts

Recontracting of the Petrojarl Varg FPSO Unit

In October 2018, we entered into a conditional agreement with Alpha Petroleum Resources Limited (or Alpha) for the Petrojarl Varg FPSO unit for Alpha's development of the Cheviot oil field on the UK continental shelf. The FPSO contract is for a seven-year fixed term from first oil, which was originally expected to occur during the second quarter of 2021 and is now delayed, after completion of a life extension and upgrade phase for the Petrojarl Varg FPSO unit at Sembcorp Marine’s shipyard in Singapore. It is intended that the Petrojarl Varg FPSO unit would be used for the entire expected life of the Cheviot field.

The effectiveness of the agreement with Alpha remains subject to satisfaction of a number of conditions precedent, including (i) initial funding from Alpha to cover the life extension and upgrade costs for the Petrojarl Varg FPSO unit, which is conditional on Alpha finalizing its project financing, and (ii) approval by relevant governmental authorities of Alpha’s final field development plan for the Cheviot field. We understand that Alpha continues to seek required funding for the project, the commencement of which will be delayed pending satisfaction of the conditions precedent. There is no assurance that the conditions will be satisfied.

Piranema Spirit FPSO Unit Contract Extension

In January 2019, we secured a three-year contract extension with Petrobras to extend the employment of the Piranema Spirit FPSO unit on the Brazilian field. The contract extension commenced in February 2019 and includes customer termination rights with 10 months' notice.

Voyageur Spirit FPSO Unit Contract Extension

In April 2018, we signed a contract extension with Premier Oil to extend the employment of the Voyageur Spirit FPSO unit on the Huntington field for an additional 12 months to April 2019. The new contract, which took effect in April 2018, includes a lower fixed charter rate component and an upside component based on oil production and oil price.

In July 2018, we entered into an additional contract extension with Premier Oil to extend the employment of the Voyageur Spirit FPSO unit on the Huntington field for an additional 12 months to April 2020. Compared to the current extension, the new one-year extension, which takes effect in April 2019, maintains the same fixed charter rate and oil production tariff elements, but provides additional potential upside from a formula based on oil price, regardless of production performance.

Rio das Ostras FPSO Unit Contract Extension

In July 2018, we entered into a contract extension with Petrobras to extend the employment of the Rio das Ostras FPSO unit for four months until November 2018, with an option to extend to January 2019. In December 2018, we entered into a further contract extension for two months until March 2019.

Shuttle Tanker Newbuildings

In July 2018, we entered into shipbuilding contracts with Samsung Heavy Industries Co. Ltd. to construct two LNG-fueled Aframax DP2 shuttle tanker newbuildings, for an estimated aggregate fully built-up cost of $270 million. These newbuildings will be constructed based on our New Shuttle Spirit design which incorporates technologies intended to increase fuel efficiency and reduce emissions, including LNG propulsion technology. Upon delivery in late-2020 through early-2021, these vessels will join our CoA shuttle tanker portfolio in the North Sea. We currently have a total of six newbuilding shuttle tankers on order.

Sale of Shuttle Tankers

In November 2018, we delivered the Navion Scandia to its buyers. We received net proceeds of $10.8 million, resulting in a gain on sale of approximately $2.8 million recorded during the fourth quarter of 2018.

In August 2018, we delivered the Stena Spirit to its buyers. We received net proceeds of $8.8 million, resulting in a gain on sale of approximately $0.4 million recorded during the third quarter of 2018, which is included in a 50%-owned subsidiary.

In June 2018, we delivered the Navion Britannia to its buyers. We received net proceeds of $10.4 million, resulting in a gain on sale of approximately $2.6 million recorded during the second quarter of 2018.

Settlement Agreements with Petrobras

In October 2018, we entered into a settlement agreement with Petróleo Brasileiro S.A. and Petroleo Netherlands B.V. - PNBV S.A. with respect to various disputes relating to the previously-terminated charter contracts of the HiLoad DP unit and Arendal Spirit UMS. As part of the settlement agreement, Petrobras agreed to pay a total amount of $96.0 million to us, $55.0 million of which was received in the fourth quarter of 2018. The remaining $41.0 million is to be paid in two separate installments of $22.0 million and $19.0 million by the end of 2020 and 2021, respectively, subject to certain potential offsets described below.

If in the ordinary course of business and prior to the end of 2021, new charter contracts are entered into with Petrobras in respect of the Arendal Spirit UMS, Cidade de Rio das Ostras (or Rio das Ostras) FPSO unit and Piranema Spirit FPSO unit, the deferred installments of $41.0 million will partly be reduced by revenue received from such new contracts in this period (or the Offset Amounts). The recent three-year contract extension with Petrobras for the Piranema Spirit FPSO unit is not expected to result in Offset Amounts being generated.

In addition, in October 2018, we entered into a further settlement agreement with Petrobras with regards to a dispute relating to the charter of the Piranema Spirit FPSO unit. Pursuant to the settlement agreement, we have agreed to a reduction in the charter rate for the FPSO unit totaling approximately $11.0 million, which was credited to Petrobras in the fourth quarter of 2018. This amount was accrued in our financial statements in prior periods, primarily in 2016 and 2017.

Financing Initiatives

Private Placement and Repurchase of Existing Bonds

In July 2018, we issued, in a U.S. private placement, a total of $700.0 million of five-year 8.5% senior unsecured bonds that mature in July 2023. Brookfield purchased $500.0 million of these bonds. The bonds contain certain incurrence-based covenants. We used a portion of the net proceeds from the issuance to (a) repurchase $225.2 million of the $300.0 million aggregate principal of our outstanding five-year 6.0% senior unsecured bonds maturing in 2019, (b) repurchase NOK 914 million of the NOK 1,000 million aggregate principal of our outstanding senior unsecured NOK bonds maturing in 2019 and a portion of the associated cross currency swap, and (c) repay at par the outstanding $200.0 million Brookfield Promissory Note maturing in 2022 and pay an associated $12.0 million early termination fee.

Arendal Spirit UMS Loan Extension

In August 2018, we extended the mandatory prepayment date for the Arendal Spirit UMS debt facility to September 30, 2019 in exchange for a principal prepayment of $18.0 million.

Common Unit Distribution Change

In January 2019, we reduced the quarterly common unit cash distributions to $nil, from $0.01 per common unit in previous quarters, in order to reinvest additional cash in the business and further strengthen our balance sheet. There are no changes to the quarterly cash distributions relating to any of our outstanding preferred units.

Board of Directors Changes

In September 2018, Brookfield appointed Mr. Craig Laurie and Mr. Denis Turcotte as members of the board of directors of our general partner (or the Board), replacing Mr. David Levenson and Mr. Bradley Weismiller, who were appointed by Brookfield in September 2017. Mr. Laurie is a Managing Partner in Brookfield’s Private Equity Group and Mr. Turcotte is a Managing Partner in Brookfield’s Private Equity Group.

Management Changes

In June 2018, Mr. David Wong stepped down from his position as Chief Financial Officer of Teekay Offshore Group Ltd., a management services company that provides services to us, to commence a new opportunity outside of the Teekay organization.

In June 2018, Mr. Tim Cowan, a Senior Vice President, Energy, at Brookfield, was appointed interim Chief Financial Officer of Teekay Offshore Group Ltd.
Effective September 3, 2018, Mr. Jan Rune Steinsland was appointed the new Chief Financial Officer of Teekay Offshore Group Ltd. Mr. Steinsland's biography is included in Item 6. Directors, Senior Management and Employees of this annual report.

Potential Additional Shuttle Tanker, FSO and FPSO Projects

Pursuant to an omnibus agreement that we entered into in connection with our initial public offering in December 2006, Teekay Corporation is obligated to offer to us its interest in certain shuttle tankers, FSO units and FPSO units that Teekay Corporation owns or may acquire in the future, provided the vessels are servicing contracts with remaining durations of greater than three years. We may also acquire other vessels that Teekay Corporation may offer us from time to time and we intend to pursue direct acquisitions from third parties and new offshore projects. Our near-to-medium term business strategy is primarily to focus on extending contracts and re-deploying existing assets on long-term charters, repaying or refinancing scheduled debt obligations and pursuing additional growth projects.
In May 2011, Teekay Corporation entered into a joint venture agreement with Ocyan to jointly pursue FPSO projects in Brazil. Ocyan is a Brazil-based company that operates in the engineering and construction, petrochemical, bioenergy, energy, oil and gas, real estate and environmental engineering sectors. Through the joint venture agreement, Ocyan is a 50 percent partner with us in the Cidade de Itajai (or Itajai) FPSO unit and the Libra FPSO unit.

Our Contracts and Charters

We generate revenues by charging customers for production, processing and storage services to oil companies operating offshore oil field installations. These services are generally provided under long-term, fixed-rate FPSO contracts, which may also contain a variable component in the form of expense adjustments or reimbursements, for incentive-based revenues dependent upon operating performance, including periodic production tariffs, which are based on the volume of oil produced, the price of oil, as well as other monthly or annual operational performance measures.

Additionally, we generate revenues by charging customers for the transportation and storage of their crude oil using our vessels. Historically, these services generally have been provided under the following basic types of contractual relationships:

- CoAs, whereby vessels which we generally operate and are responsible for crewing, carry an agreed quantity of cargo for a customer over a specified trade route within a given period of time;
- Time charters, whereby vessels which we operate and are responsible for crewing, are chartered to customers for a fixed period of time at rates that are generally fixed, but may contain a variable component based on expense adjustments due to inflation, interest rates or current market rates;
- Bareboat charters, whereby customers charter vessels for a fixed period of time at rates that are generally fixed, but the customers are responsible for the operation and maintenance of the vessels with their own crew as well as any expenses unique to a particular voyage; and
- Voyage charters, which are charters for a particular voyage and are generally for shorter intervals that are priced on a current, or "spot," market rate.

We also generate revenue from the operation of VOC systems on certain of our shuttle tankers, and the management of certain vessels on behalf of third parties who are the owners or charterers of these vessels. Such services include the arrangement of third party goods and services for the vessel's owner or charterer.

The table below illustrates the primary distinctions among these types of charters and contracts:

	Contract of Affreightment	Time Charter	Bareboat Charter	Voyage Charter [1]	FPSO Contracts
Typical contract length	One year or more	One year or more	One year or more	Single voyage	Long-term

Hire rate basis (2)	Typically daily	Daily	Daily	Varies	Daily
Voyage expenses (3)	We pay	Customer pays	Customer pays	We pay	Not applicable
Vessel operating expenses	We pay	We pay	Customer pays	We pay	We pay
Off hire (4)	Customer typically does not pay	Varies	Customer typically pays	Customer does not pay	Not applicable
Shutdown (5)	Not applicable	Not applicable	Not applicable	Not applicable	Varies

(1) Under a consecutive voyage charter, the customer pays for idle time.
(2) "Hire rate" refers to the basic payment from the charterer for the use of the vessel.
(3) Voyage expenses are all expenses unique to a particular voyage, including any bunker fuel expenses, port fees, cargo loading and unloading expenses, canal tolls, agency fees and commissions.
(4) "Off hire" refers to the time a vessel is not available for service.
(5) "Shutdown" refers to the time production services are not available.

Important Financial and Operational Terms and Concepts
We use a variety of financial and operational terms and concepts. These include the following:

Revenues. Revenues primarily include revenues from FPSO contracts, time charters, contracts of affreightment, bareboat charters, voyage charters and management fees. Revenues are affected by charter hire rates, the number of days a vessel operates and the daily production volume and the price of oil on FPSO units. Revenues are also affected by the mix of business between FPSO contracts, time charters, contracts of affreightment, bareboat charters and voyage charters. Hire rates for voyage charters are more volatile, as they are typically tied to prevailing market rates at the time of a voyage.

Voyage Expenses. Voyage expenses are all expenses unique to a particular voyage, including any bunker fuel expenses, port fees, cargo loading and unloading expenses, canal tolls, agency fees and commissions. Voyage expenses are typically paid by the customer under time charters and bareboat charters and by the shipowner under voyage charters and contracts of affreightment. When we pay voyage expenses, they typically are added to the hire rates at an approximate cost.

Net Revenues. Net revenues represent revenues less voyage expenses incurred by us. Because the amount of voyage expenses we incur for a particular charter depends upon the type of charter, we use net revenues to improve the comparability between periods of reported revenues that are generated by the different types of charters. We principally use net revenues, a non-GAAP financial measure, because it provides more meaningful information to us about the deployment of our vessels and their performance upon time charter equivalent (or TCE) rates, than revenues, the most directly comparable financial measure under U.S. generally accepted accounting principles (or GAAP).

Vessel Operating Expenses. Under all types of charters and contracts for our vessels, except for bareboat charters, we are responsible for vessel operating expenses, which include crewing, repairs and maintenance, ship management services, insurance, stores, lube oils and communication expenses. The two largest components of our vessel operating expenses are crew costs and repairs and maintenance. The strengthening or weakening of the U.S. Dollar relative to foreign currencies may result in significant decreases or increases, respectively, in our vessel operating expenses, depending on the currencies in which some of such expenses are incurred.

Time-Charter Hire Expenses. Time-charter hire expenses represent the cost to charter-in a vessel for a fixed period of time.

Income from Vessel Operations. To assist us in evaluating operations by segment, we sometimes analyze the income we receive from each segment after deducting operating expenses, but prior to the deduction of interest expense, interest income, income taxes, realized and unrealized gains or losses on non-designated derivative instruments, equity income, foreign currency exchange loss, losses on debt repurchases and other income (expenses) - net.

Dry docking. We must periodically dry dock our shuttle tankers and towage and offshore installation vessels for inspection, repairs and maintenance and any modifications to comply with industry certification or governmental requirements. We may dry dock FSO units if we desire to qualify them for shipping classification. Generally, we dry dock each of our vessels every two and a half to five years, depending upon the type of vessel and its age. We capitalize a substantial portion of the costs incurred during dry docking and amortize those costs on a straight-line basis from the completion of a dry docking over the estimated useful life of the dry dock. We expense costs related to routine repairs and maintenance performed during dry docking that do not improve or extend the useful lives of the assets, and for annual class survey costs on our FPSO units or our UMS. The number of dry dockings undertaken in a given period and the nature of the work performed determine the level of dry-docking expenditures.

Depreciation and Amortization. Depreciation and amortization expense typically consists of:

- charges related to the depreciation of the historical cost of our fleet (less an estimated residual value) over the estimated useful lives of the vessels or equipment; and
- charges related to the amortization of dry-docking expenditures over the estimated useful life of the dry docking.

Calendar-Ship-Days. Calendar-ship-days are the total number of calendar days that our vessels were in our possession during a period. We use calendar-ship-days primarily to highlight changes in vessel operating expenses, time-charter hire expense and depreciation and amortization. Calendar-ship days are based on our owned and chartered-in fleet, including vessels owned by our 50% and 89% owned subsidiaries, but excluding vessels owned by our 50% owned investments in equity accounted joint ventures.

Items You Should Consider When Evaluating Our Results

You should consider the following factors when evaluating our historical financial performance and assessing our future prospects:

- The size of and types of vessels in our fleet continues to change. Our results of operations reflect changes in the size and composition of our fleet due to certain vessel deliveries and vessel dispositions. Please read "Results of Operations" below for further details about vessel dispositions and deliveries. Due to the nature of our business, we expect our fleet to continue to fluctuate in size and composition.
- Our financial results are affected by fluctuations in currency exchange rates. Under GAAP, all foreign currency-denominated monetary assets and liabilities (such as cash and cash equivalents, restricted cash, accounts receivable, accounts payable, due to and from affiliates, long-term debt and deferred income taxes) are revalued and reported based on the prevailing exchange rate at the end of the period. Fluctuations in the value of the Norwegian Krone, British Pound, Euro, Australian Dollar, Canadian Dollar or Brazilian Real relative to the U.S. Dollar, may result in increased or decreased vessel operating and general and administrative expenses if the strength

of the U.S. Dollar declines or increases, respectively, relative to the Norwegian Krone, British Pound, Euro, Australian Dollar, Canadian Dollar or Brazilian Real. We periodically enter into foreign currency forward contracts to hedge portions of these forecasted expenditures.

- Our financial results are affected by fluctuations in the fair value of our derivatives instruments. The change in fair value of our interest rate swaps, cross currency swaps and foreign currency forward contracts are included in our net (loss) income because all of our derivative instruments as at December 31, 2018, are not designated in qualifying hedging relationships for accounting purposes. Although we believe that these non-designated derivative instruments are economic hedges, the changes in their fair value are included in our consolidated statements of (loss) income as an unrealized gain or loss on derivatives for interest rate swaps and foreign currency forward contracts and as foreign exchange loss for cross currency swaps. The unrealized gain or loss relating to changes in fair value of our derivative instruments does not affect our consolidated cash flows, liquidity or cash distributions to our common unitholders, preferred unit holders or our general partner.
- Our operations are seasonal and our financial results vary as a consequence of dry dockings. Historically, the utilization of FPSO units and shuttle tankers in the North Sea is higher in the winter months, as favorable weather conditions in the warmer months provide opportunities for repairs and maintenance to our vessels and to offshore oil platforms. Downtime for repairs and maintenance generally reduces oil production and, thus, transportation requirements. In addition, we generally do not earn revenue when our vessels are in scheduled and unscheduled dry docking. Four shuttle tankers are scheduled for dry docking in 2019. From time to time, unscheduled dry dockings may cause additional fluctuations in our financial results.

We manage our business and analyze and report our results of operations on the basis of our six business segments: the FPSO segment, the shuttle tanker segment, the FSO segment, the UMS segment, the towage and offshore installation vessels segment, and the conventional tanker segment, each of which are discussed below:

Results of Operations

Year Ended December 31, 2018 versus Year Ended December 31, 2017

FPSO Segment

As at December 31, 2018, our FPSO fleet consisted of the Petrojarl Knarr, the Petrojarl Varg, the Rio das Ostras, the Piranema Spirit, the Voyageur Spirit, and the Petrojarl I FPSO units, all of which we own 100%, and the Itajai and the Libra FPSO units, of which we own 50% through our joint ventures with Ocyan. The Petrojarl Varg is currently in lay-up. We also provide management services for three FPSO units owned by certain subsidiaries of Teekay Corporation.

FPSO units provide production, processing and storage services to oil companies operating offshore oil field installations. These services are typically provided under long-term, fixed-rate contracts, some of which also include certain incentive compensation or penalties based on the level of oil production, the price of oil and other operational measures. Historically, the utilization of FPSO units and other vessels in the North Sea, where the Petrojarl Knarr and Voyageur Spirit FPSO units operate, is higher in the winter months, as favorable weather conditions in the summer months provide opportunities for repairs and maintenance to our units and the offshore oil platforms, which generally reduces oil production. The Petrojarl I FPSO unit operates under a charter rate profile with a lower day rate during the first 18 months of production. During the final three and a half years of the contract, the charter contract will increase to a higher day rate plus an oil price and production tariff. We have accounted for the fixed daily charter rate on a straight-line basis over the duration of the charter contract. The strengthening or weakening of the U.S. Dollar relative to the NOK, Brazilian Real, and British Pound may result in significant decreases or increases, respectively, in our revenues and vessel operating expenses.

The following table presents the FPSO segment's operating results for 2018 and 2017, and also provides a summary of the calendar-ship-days for the FPSO segment. The table excludes the results of the Itajai and the Libra FPSO units, which are accounted for as equity accounted investments.

(in thousands of U.S. Dollars, except calendar-ship-days and percentages)	Year Ended December 31, 2018	2017	% Change
Revenues	533,186	458,388	16.3
Vessel operating expenses	(214,623)	(149,153)	43.9
Depreciation and amortization	(145,451)	(143,559)	1.3
General and administrative [(1)]	(34,052)	(33,046)	3.0
Write-down of vessels	(180,200)	(265,229)	(32.1)
Restructuring charge	(1,520)	(450)	237.8
Loss from vessel operations	(42,660)	(133,049)	(67.9)
Calendar-Ship-Days			
Owned Vessels	2,190	2,190	—

(1)Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to the FPSO segment based on estimated use of corporate resources). See the discussion under "Other Operating Results" below.

Revenues. Revenues increased for 2018 compared to 2017, primarily due to:

- an increase of $51.5 million due to the gross-up of certain reimbursable operating expenses required by the adoption of Accounting Standards Codification 606, Revenue From Contracts With Customers (this increase is mostly offset by a corresponding increase in vessel operating expenses, as indicated below);
- an increase of $47.7 million due to commencement of the charter contract of the Petrojarl I FPSO unit in May 2018;
- an increase of $22.7 million due to the accelerated amortization of an in-process revenue contract relating to the Piranema Spirit FPSO unit;
- an increase of $6.9 million due to revenue received for an offshore field study associated with the Petrojarl Varg FPSO unit that was substantially completed in the first quarter of 2018 (this revenue is offset by a corresponding increase in vessel operating expenses incurred, as indicated below); and
- an increase of $4.7 million mainly due to project revenue earned on the Petrojarl Knarr FPSO unit;

partially offset by

- a decrease of $43.1 million mainly due to the Voyageur Spirit FPSO unit operating at reduced charter rates related to a charter contract extension from April 2018 to April 2020; and
- a decrease of $20.8 million mainly due to a rate reduction on the Rio das Ostras FPSO unit related to its charter extension from January 2018.

Vessel operating expenses. Vessel operating expenses increased for 2018 compared to 2017, primarily due to:

- an increase of $50.4 million due to the gross-up of certain reimbursable operating expenses required by the adoption of Accounting Standards Codification 606, Revenue From Contracts With Customers (this increase is offset by a corresponding increase in revenues);
- an increase of $14.7 million due to the commencement of the charter contract of the Petrojarl I FPSO unit in May 2018; and
- an increase of $9.1 million due to expenditures incurred for an offshore field study for the Petrojarl Varg FPSO unit that was substantially completed in the first quarter of 2018 (this increase is mostly offset by a corresponding increase in revenues);

partially offset by

- a decrease of $5.4 million mainly due to lower repair and maintenance expenses on the Rio das Ostras FPSO unit, as the unit prepares for its decommissioning in early-2019.

Write-down of vessels. Write-down of vessels for 2018 consists of the write-down of the Piranema Spirit FPSO unit and the Rio das Ostras FPSO unit as a result of a reassessment of the future redeployment assumptions for both units. Write-down of vessels for 2017 consists of the write-down of the Petrojarl I FPSO unit due to increased costs associated with additional upgrade work required and liquidated damages associated with the delay in the commencement of operations of the unit and the write-down of the Rio das Ostras FPSO unit due to a change in the future operating plans for the unit.

Shuttle Tanker Segment

As at December 31, 2018, our shuttle tanker fleet consisted of 26 vessels that operate under fixed-rate CoAs, time charters and bareboat charters, two vessels that are currently in lay-up, six shuttle tanker newbuildings which are expected to deliver in late-2019 through early-2021, and the HiLoad DP unit, which is currently in lay-up. Of these 35 shuttle tankers, four are owned through 50%-owned subsidiaries and two were chartered-in. The remaining vessels are owned 100% by us. All of our operating shuttle tankers, with the exception of two shuttle tankers that are currently trading as conventional tankers and the HiLoad DP unit, provide transportation services to energy companies in the North Sea, Brazil and the East Coast of Canada. Our shuttle tankers occasionally service the conventional spot tanker market. The strengthening or weakening of the U.S. Dollar relative to the NOK, Euro and Brazilian Real may result in significant decreases or increases, respectively, in our vessel operating expenses.

The following table presents the shuttle tanker segment's operating results for 2018 and 2017, and compares its net revenues (which is a non-GAAP financial measure) for 2018 and 2017, to revenues, the most directly comparable GAAP financial measure, for the same years. The following table also provides a summary of the changes in calendar-ship-days by owned and chartered-in vessels for the shuttle tanker segment:

47

	Year Ended December 31,		
(in thousands of U.S. Dollars, except calendar-ship-days and percentages)	2018	2017	% Change
Revenues	636,413	536,852	18.5
Voyage expenses	(109,796)	(80,964)	35.6
Net revenues	526,617	455,888	15.5
Vessel operating expenses	(149,226)	(129,517)	15.2
Time-charter hire expenses	(36,421)	(62,899)	(42.1)
Depreciation and amortization	(155,932)	(125,648)	24.1
General and administrative (1)	(21,763)	(17,425)	24.9
(Write-down) and gain on sale of vessels	(43,155)	(51,741)	(16.6)
Restructuring charge	—	(210)	(100.0)
Income from vessel operations	120,120	68,448	75.5
Calendar-Ship-Days			
Owned Vessels	10,329	10,322	0.1
Chartered-in Vessels	735	1,248	(41.1)
Total	11,064	11,570	(4.4)

(1)Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to the shuttle tanker segment based on estimated use of corporate resources). See the discussion under “Other Operating Results” below.

The average size of our owned shuttle tanker fleet was consistent for 2018 compared to 2017. The delivery of three newbuilding shuttle tankers in late-2017 and early-2018 was offset by the sale of the Navion Marita, Navion Britannia, Stena Spirit and Navion Scandia shuttle tankers in November 2017, June 2018, August 2018 and November 2018, respectively. Six shuttle tanker newbuildings have been excluded from calendar-ship-days, as these vessels were not yet delivered to us as at December 31, 2018.

The average size of our chartered-in shuttle tanker fleet decreased for 2018,compared to 2017, due to the redelivery of the Jasmine Knutsen shuttle tanker to its owner in January 2018 and decreased spot-in chartering of shuttle tankers.

Net revenues. Net revenues increased for 2018 compared to 2017, primarily due to:

- an increase of $55.0 million due to a settlement agreement with Petrobras in relation to the previously-terminated charter contract of the HiLoad DP unit recorded in 2018;
- an increase of $16.1 million due to the gross-up of certain reimbursable operating expenses required by the adoption of Accounting Standards Codification 606, Revenue From Contracts With Customers (this increase is mostly offset by a corresponding increase in vessel operating expenses, as indicated below);
- an increase of $13.7 million due to the commencement of operations of the Beothuk Spirit shuttle tanker newbuilding in late-2017 and the Norse Spirit and Dorset Spirit shuttle tanker newbuildings during 2018, servicing the East Coast of Canada charter contracts; and
- an increase of $7.1 million due to higher average rates in our CoA fleet and rate escalations on certain vessels in our time-charter fleet;

partially offset by

- a decrease of $12.5 million due to the timing of dry-docking of vessels; and
- a decrease of $8.4 million due to the redelivery of the Nordic Spirit and Stena Spirit shuttle tanker during the second quarter of 2018 and subsequent sale of the Stena Spirit shuttle tanker in August 2018.

Vessel operating expenses. Vessel operating expenses increased for 2018 compared to 2017, primarily due to:

- an increase of $15.5 million due to the gross-up of certain reimbursable operating expenses required by the adoption of Accounting Standards Codification 606, Revenue From Contracts With Customers (this increase is offset by a corresponding increase in net revenues); and

- an increase of $14.4 million due to the commencement of operations of the Beothuk Spirit shuttle tanker newbuilding in late-2017 and the Norse Spirit and Dorset Spirit shuttle tanker newbuildings during 2018;

partially offset by

- a decrease of $7.2 million mainly due to the timing of repairs and crew composition compared to the prior year; and
- a decrease of $5.1 million due to the sale of the Navion Marita, Navion Britannia and Navion Scandia shuttle tanker in November 2017, June 2018 and November 2018, respectively.

Time-charter hire expenses. Time-charter hire expenses decreased for 2018 compared to 2017, primarily due to the re-delivery of the Jasmine Knutsen in January 2018, which was replaced by the Beothuk Spirit shuttle tanker newbuilding in the East Coast of Canada.

Depreciation and amortization. Depreciation and amortization expense increased for 2018 compared to 2017, primarily due to:

- an increase of $31.0 million due to a change in the estimated useful life of the tanker component for all shuttle tankers from 25 years to 20 years, effective January 1, 2018, and a decrease in the residual value of certain shuttle tankers;
- an increase of $11.8 million due to the commencement of operations of the Beothuk Spirit shuttle tanker newbuilding in late-2017 and the Norse Spirit and Dorset Spirit shuttle tanker newbuildings during 2018; and
- an increase of $4.8 million due to the timing of dry-docking of vessels;

partially offset by

- a decrease of $13.3 million mainly due to the write-down of three vessels and the sale of one vessel during 2017 and the write-down of three vessels and sale of three vessels during 2018.

(Write-down) and gain on sale of vessels. (Write-down) and gain on sale of vessels was ($43.2) million for the year ended December 31, 2018 and includes a $19.2 million write-down of the HiLoad DP unit as a result of a change in the operating plans for the vessel, a $14.9 million write-down of the Nordic Spirit shuttle tanker and a $14.8 million write-down of the Stena Spirit shuttle tanker as a result of their charter contract expiration during 2018 and a change in the operating plans for these vessels, partially offset by a $2.8 million gain on the sale of the Navion Scandia shuttle tanker during 2018, a $2.6 million gain on the sale of the Navion Britannia shuttle tanker during 2018, and a $0.4 million gain on the sale of the Stena Spirit shuttle tanker during 2018.

(Write-down) and gain on sale of vessels was ($51.7) million for the year ended December 31, 2017 and includes a $26.3 million write-down of the HiLoad DP unit as a result of a change in expectations for the future opportunities of the unit, a $10.8 million write-down of the Nordic Rio shuttle tanker and a $9.3 million write-down of the Nordic Brasilia shuttle tanker as a result of a change in the operating plans for these vessels due to the redelivery of these vessels from their charterer after completing their bareboat contracts in July 2017 and a $5.1 million write-down of the Navion Marita shuttle tanker as a result of the expected sale of the vessel in the third quarter of 2017, partially offset by a subsequent $0.3 million gain on the sale of the Navion Marita shuttle tanker during 2017.

FSO Segment

As at December 31, 2018, our FSO fleet consisted of six units that operate under fixed-rate time charters or fixed-rate bareboat charters, for which our ownership interests range from 89% to 100%.

FSO units provide an on-site storage solution to oil field installations that have no oil storage facilities or that require supplemental storage. Our revenues and vessel operating expenses for the FSO segment are affected by fluctuations in currency exchange rates, as a significant component of revenues are earned and vessel operating expenses are incurred in NOK and Australian Dollars for certain vessels. The strengthening or weakening of the U.S. Dollar relative to the NOK or Australian Dollar may result in significant decreases or increases, respectively, in our revenues and vessel operating expenses.

The following table presents the FSO segment's operating results for 2018 and 2017, and compares its net revenues (which is a non-GAAP financial measure) for 2018 and 2017, to revenues, the most directly comparable GAAP financial measure, for the same years. The following table also provides a summary of the changes in calendar-ship-days for the FSO segment:

	Year Ended December 31,		
(in thousands of U.S. Dollars, except calendar-ship-days and percentages)	2018	2017	% Change
Revenues	136,557	66,901	104.1
Voyage expenses	(769)	(1,172)	(34.4)
Net revenues	135,788	65,729	106.6
Vessel operating expenses	(42,913)	(25,241)	70.0
Depreciation and amortization	(44,077)	(19,406)	127.1

General and administrative [1]	(2,174)	(1,864)	16.6
(Write-down) and gain on sale of vessels	—	(1,108)	(100.0)
Income from vessel operations	46,624	18,110	157.4
Calendar-Ship-Days			
Owned Vessels	2,190	2,468	(11.3)

(1)Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to the FSO segment based on estimated use of corporate resources). See the discussion under "Other Operating Results" below.

The average number of our FSO units decreased for 2018 compared to 2017, due to the sale of the Navion Saga FSO unit in October 2017.

Net revenues, vessel operating expenses and depreciation and amortization. Net revenues, vessel operating expense and depreciation and amortization expense increased for 2018 compared to 2017, primarily due to the Randgrid FSO unit commencing operations in October 2017.

UMS Segment

As at December 31, 2018, our UMS fleet consisted of one unit, the Arendal Spirit UMS, in which we own a 100% interest and which is currently in lay-up.

The UMS is used primarily for offshore accommodation, storage and support for maintenance and modification projects on existing offshore installations, or during the installation and decommissioning of large floating exploration, production and storage units, including FPSO units, floating liquefied natural gas (FLNG) units and floating drill rigs. The UMS is available for world-wide operations, excluding operations within the Norwegian Continental Shelf, and includes a DP3 keeping system that is capable of operating in deep water and harsh weather.

The following table presents the UMS segment's operating results for 2018 and 2017, and compares its net revenues (which is a non-GAAP financial measure) for 2018 and 2017, to revenues, the most directly comparable GAAP financial measure, for the same years. The following table also provides a summary of the changes in calendar-ship-days for the UMS segment:

	Year Ended December 31,		
(in thousands of U.S. Dollars, except calendar-ship-days and percentages)	2018	2017	% Change
Revenues	36,536	4,236	762.5
Voyage expenses	(47)	(1,152)	(95.9)
Net revenues	36,489	3,084	1,083.2
Vessel operating expenses	(3,679)	(33,656)	(89.1)
Depreciation and amortization	(6,611)	(6,566)	0.7
General and administrative [(1)]	(3,547)	(5,068)	(30.0)
Restructuring charge	—	(2,004)	(100.0)
Income (loss) from vessel operations	22,652	(44,210)	151.2
Calendar-Ship-Days			
Owned Vessels	365	365	—

(1)Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to the UMS segment based on estimated use of corporate resources). See the discussion under "Other Operating Results" below.

Revenues. Revenues increased for 2018 compared to 2017, mainly due to $36.5 million recorded in 2018 related to a settlement agreement with Petrobras in relation to the previously-terminated charter contract of the Arendal Spirit UMS.

Vessel operating expenses. Vessel operating expenses decreased for 2018 compared to 2017, due to the Arendal Spirit UMS charter contract termination in April 2017 and the subsequent lay-up of the unit during the fourth quarter of 2017, and the remaining deferred mobilization costs of $14.3 million relating to the charter contract, recognized during 2017.

Restructuring charge. Restructuring charge for 2017 relates to crew and onshore staff severance costs relating to the termination of the charter contract of the Arendal Spirit UMS and the unit proceeding to lay-up.

Towage and Offshore Installation Vessels Segment

As at December 31, 2018, our towage vessel fleet consisted of ten long-distance towage and offshore installation vessels. Two of the vessels are currently in lay-up. We own a 100% interest in each of the vessels in our towage fleet.

Long-distance towage and offshore installation vessels are used for the towage, station-keeping, installation and decommissioning of large floating objects, such as exploration, production and storage units, including FPSO units, FLNG units and floating drill rigs.

The following table presents the towage and offshore installation vessels segment's operating results for 2018 and 2017, and compares its net revenues (which is a non-GAAP financial measure) for 2018 and 2017, to revenues, the most directly comparable GAAP financial measure, for the same years. The following table also provides a summary of the changes in calendar-ship-days by owned and chartered-in vessels for the towage and offshore installation vessels segment.

	Year Ended December 31,		
(in thousands of U.S. Dollars, except calendar-ship-days and percentages)	2018	2017	% Change
Revenues	53,327	38,771	37.5
Voyage expenses	(28,925)	(17,727)	63.2
Net revenues	24,402	21,044	16.0
Vessel operating expenses	(27,346)	(21,074)	29.8
Time-charter hire expenses	—	(925)	(100.0)
Depreciation and amortization	(20,323)	(15,578)	30.5
General and administrative [1]	(3,531)	(4,486)	(21.3)
Loss from vessel operations	(26,798)	(21,019)	27.5
Calendar-Ship-Days			
Owned Vessels	3,618	2,839	27.4
Chartered-in Vessels	—	52	(100.0)
Total	3,618	2,891	25.1

(1)Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to the towage and offshore installation vessels segment based on estimated use of corporate resources). See the discussion under “Other Operating Results” below.

The average number of our towage and offshore installation vessels increased for 2018 compared to 2017, due to the delivery of three newbuilding vessels, the ALP Defender, ALP Sweeper and ALP Keeper, in June 2017, October 2017 and February 2018, respectively.

Net revenues, vessel operating expenses and depreciation and amortization expense. Net revenues, vessel operating expenses and depreciation and amortization expense increased for 2018 compared to 2017, mainly due to the timing of delivery of the newbuilding vessels. Net revenues and vessel operating expenses were also impacted by the lay-up of two vessels since late-2017.

Conventional Tanker Segment

As at December 31, 2018, our conventional tanker fleet consisted of two in-chartered conventional tankers, both of which are currently trading in the spot conventional tanker market. The time-charter-in contracts for both of the conventional tankers are scheduled to expire in March 2019.

The following table presents the conventional tanker segment’s operating results for 2018 and 2017, and compares its net revenues (which is a non-GAAP financial measure) for 2018 and 2017, to revenues, the most directly comparable GAAP financial measure, for the same years. The following table also provides a summary of the changes in calendar-ship-days for the conventional tanker segment:

	Year Ended December 31,		
(in thousands of U.S. Dollars, except calendar-ship-days and percentages)	2018	2017	% Change
Revenues	21,325	14,022	52.1
Voyage expenses	(12,453)	(359)	3,368.8
Net revenues	8,872	13,663	(35.1)
Vessel operating recoveries	—	10	(100.0)
Time-charter hire expenses	(16,195)	(16,491)	(1.8)
General and administrative [1]	(360)	(360)	—
Loss from vessel operations	(7,683)	(3,178)	141.8
Calendar-Ship-Days			
Chartered-in Vessels	730	730	—

(1)Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to the conventional tanker segment based on estimated use of corporate resources). See the discussion under “Other Operating Results” below.

Net revenues. Net revenues decreased for 2018 compared to 2017, mainly due to the termination of the time-charter contract of the Blue Power in late-2017 and the vessel operating in the spot conventional tanker market during 2018 at lower rates than those received under the time-charter contract.

Other Operating Results

General and administrative. General and administrative expenses increased to $65.4 million for 2018, compared to $62.2 million for 2017. General and administrative expenses increased mainly due to the Randgrid FSO unit commencing operations in the fourth quarter of 2017, partially offset by a decrease in legal fees to support certain claims (please refer to Item 18 – Financial Statements: Note 14 – Commitments and Contingencies).

Interest expense. Interest expense increased to $199.4 million for 2018, compared to $154.9 million for 2017, primarily due to:

- an increase of $27.1 million due to the delivery of vessel newbuildings, conversions and upgrades in late-2017 and early-2018;
- an increase of $15.1 million due to an increase in the weighted-average interest rate on our existing and refinanced long-term debt, partially offset by a lower average existing and refinanced debt balance; and
- an increase of $5.0 million due to the drawdown of the $125.0 million revolving credit facility provided by Brookfield and Teekay Corporation during the second quarter of 2018;

partially offset by

- a decrease of $5.8 million due to non-cash guarantee fees to Teekay Corporation associated with the long-term financing for the East Coast of Canada shuttle tanker newbuildings and certain of our interest rate swaps and cross currency swaps, which guarantees were terminated as part of the strategic partnership with Brookfield in September 2017.

Realized and unrealized gain (loss) on derivative instruments. Net realized and unrealized gain (loss) on non-designated derivative instruments were $12.8 million for 2018 compared to ($42.9) million for 2017. These totals are comprised of net gains on interest rate swaps of $18.4 million in 2018 compared to net losses of $45.2 million in 2017 and net losses on foreign currency forward contracts of $5.6 million in 2018 compared to net gains of $2.3 million in 2017.

During 2018 and 2017, we had interest rate swap agreements with aggregate average outstanding notional amounts of approximately $1.6 billion and $1.8 billion, respectively, and average fixed rates of approximately 3.5% and 3.4%, respectively. Short-term variable benchmark interest rates during 2018 and 2017 were generally 2.9% or less and 1.8% or less, respectively, and as such, we incurred realized losses of $38.0 million and $78.3 million during 2018 and 2017, respectively, under the interest rate swap agreements. The decrease in realized loss was also due to lower settlement fees associated with early terminations of certain interest rate swaps that occurred during 2017. We also recognized a $23.3 million increase in unrealized gains on interest rate swaps due to a higher increase in long-term LIBOR benchmark rates during 2018 compared to those during 2017.

During 2018 and 2017, we were committed to foreign currency forward contracts to hedge portions of our forecasted expenditures in NOK and Euro, which resulted in a realized loss of $1.2 million and a realized gain of $0.9 million during 2018 and 2017, respectively. The realized amounts were partially offset by a $5.8 million increase in the unrealized loss on foreign currency forward contracts mainly due to lower average forward rates on existing foreign currency forward contracts as at December 31, 2018 compared to December 31, 2017.

Please see Item 5 - Critical Accounting Estimates: Valuation of Derivative Instruments, which explains how our derivative instruments are valued, including the significant factors and uncertainties in determining the estimated fair value and why changes in these factors result in material variances in realized and unrealized gains and losses on derivative instruments.

Equity income. Equity income was $39.5 million for 2018 compared to $14.4 million for 2017. The increase in equity income was primarily due to the commencement of operations of the Libra FPSO unit in the fourth quarter of 2017.

Foreign currency exchange loss. Foreign currency exchange loss was $9.4 million for 2018, compared to $14.0 million for 2017. Our foreign currency exchange loss was due primarily to the relevant period-end revaluation of NOK-denominated monetary assets and liabilities for financial reporting purposes and the realized and unrealized gains and losses on our cross currency swaps. Gains on NOK-denominated net monetary liabilities reflect a stronger U.S. Dollar against the NOK on the date of revaluation or settlement compared to the rate in effect at the beginning of the period. Losses on NOK-denominated net monetary liabilities reflect a weaker U.S. Dollar against the NOK on the date of revaluation or settlement compared to the rate in effect at the beginning of the period. There were additional realized and unrealized losses of $7.4 million for 2018 (2017 - losses of $9.5 million) on all other monetary assets and liabilities.

For 2018, foreign currency exchange loss includes a net foreign exchange loss of $1.0 million (2017 - gain of $7.7 million) on the cross currency swaps. The increase in net foreign exchange loss relating to the cross currency swaps is mainly due to unrealized gains recognized during 2017 due to the weakening of the U.S. Dollar against the NOK and lower notional cross currency swap balances in 2018. There was an additional net foreign exchange loss during 2018 of $1.0 million (2017 - loss of $12.2 million) on the revaluation and settlement of the NOK-denominated debt.

Losses on debt repurchases. Losses on debt repurchases of $55.5 million for 2018 relates to the prepayment of the $200.0 million Brookfield Promissory Note and the repurchases of $225.2 million of the existing $300.0 million five-year senior unsecured bonds maturing in July 2019, and NOK 914 million of the existing NOK 1,000 million senior unsecured bonds maturing in January 2019. The losses on debt repurchases are comprised of an acceleration of non-cash accretion expense of $31.5 million resulting from the difference between the $200.0 million settlement amount of the Brookfield Promissory Note at its par value and its carrying value of $168.5 million and an associated early termination fee of $12.0 million paid to Brookfield, as well as 2.0% - 2.5% premiums on the repurchase of the bonds and the write-off of capitalized loan costs. The carrying value of the Brookfield Promissory Note was lower than face value due to it being recorded at its relative fair value based on the allocation of net proceeds invested by Brookfield on September 25, 2017.

Other (expense) income - net. Other (expense) income - net of ($4.6) million for 2018 mainly relates to the settlement of a claim with Transocean Offshore International Ventures Limited in early-2018 relating to a grounding incident involving one of our towage and offshore installation vessels, the ALP Forward, in August 2016. Other income of $14.2 million for 2017 was mainly due to a partial reversal of a previously accrued contingent liability associated with the estimated damages from the cancellation of the UMS construction contracts, partially offset by a settlement entered into between CeFront Technology AS (or CeFront) and certain subsidiaries of ours to settle certain outstanding claims against us in September 2017 (please refer to Item 18 - Financial Statements: Note 14b Commitments and Contingencies).

Income tax (expense) recovery. Income tax (expense) recovery was ($22.7) million for 2018 compared to $0.1 million for 2017. The increase during 2018 was primarily due to increases in our valuation allowances on certain Norwegian deferred tax assets associated with our shuttle tanker and FPSO fleet, due to changes in the assumptions for future taxable income.

Year Ended December 31, 2017 versus Year Ended December 31, 2016

FPSO Segment

As at December 31, 2017, our FPSO fleet consisted of the Petrojarl Knarr, the Petrojarl Varg, the Rio das Ostras, the Piranema Spirit, the Voyageur Spirit, and the Petrojarl I FPSO units, all of which we own 100%, and the Itajai and the Libra FPSO units, of which we own 50%. One equity accounted FPSO unit, the Libra FPSO unit owned through our 50/50 joint venture with Ocyan, achieved first oil and commenced its 12-year charter contract in November 2017. The Petrojarl I FPSO unit completed its upgrades and arrived on the Atlanta field in January 2018 and commenced its five-year charter contract with QGEP in May 2018. One FPSO unit, the Petrojarl Varg, was in lay-up as at December 31, 2017.

The following table presents the FPSO segment's operating results for 2017 and 2016, and also provides a summary of the calendar-ship-days for the FPSO segment. The table excludes the results of the Itajai and the Libra FPSO units, which are accounted for as equity accounted investments.

	Year Ended December 31,		
(in thousands of U.S. Dollars, except calendar-ship-days and percentages)	2017	2016	% Change
Revenues	458,388	495,223	(7.4)
Vessel operating expenses	(149,153)	(165,346)	(9.8)
Depreciation and amortization	(143,559)	(149,198)	(3.8)
General and administrative [(1)]	(33,046)	(35,971)	(8.1)
Write-down of vessels	(265,229)	—	100.0
Restructuring charge	(450)	(4,444)	(89.9)
(Loss) income from vessel operations	(133,049)	140,264	(194.9)
Calendar-Ship-Days			
Owned Vessels	2,190	2,196	(0.3)

(1)Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to the FPSO segment based on estimated use of corporate resources). See the discussion under "Other Operating Results" below.

Revenues. Revenues decreased for 2017 compared to 2016, primarily due to:

- a decrease of $32.2 million due to no longer receiving the capital portion of the charter hire for the Petrojarl Varg FPSO unit since February 1, 2016 and the unit being in lay-up since August 1, 2016 due to the termination of the charter contract by Repsol; and
- a decrease of $8.0 million due to revenue received for offshore field studies associated with the Petrojarl Varg FPSO unit and reimbursement of business development costs during 2016 (this revenue was partially offset by vessel operating expenses incurred, as indicated below);

partially offset by

- an increase of $2.2 million mainly due to the receipt of payments for higher reimbursable expenses incurred on the Voyageur Spirit FPSO unit (this revenue is offset by operating expenses incurred, as indicated below); and
- an increase of $2.0 million mainly due to a one-time performance bonus earned and a rate escalation relating to the Petrojarl Knarr FPSO unit during the third quarter of 2017.

Vessel Operating Expenses. Vessel operating expenses decreased for 2017 compared to 2016, primarily due to:

- a decrease of $15.9 million due to lower costs as the Petrojarl Varg FPSO unit was decommissioned at the end of July 2016 and is now in lay-up;
- a decrease of $5.8 million due to lower crew and repair and maintenance costs for the Petrojarl Knarr FPSO unit relating to the unit preparing for its final performance test that was completed during the third quarter of 2016; and
- a decrease of $5.0 million due to expenditures incurred for offshore field studies for the Petrojarl Varg FPSO unit in 2016;

partially offset by

- an increase of $6.3 million due to higher pre-operational costs incurred on the Petrojarl I FPSO unit as the unit completed upgrades and is undergoing installation before commencing operations during the second quarter of 2018;

- an increase of $2.3 million due to higher repair and maintenance costs on the Voyageur Spirit FPSO unit which are reimbursed by the charterer; and

- an increase of $2.3 million due to the weakening of the U.S. Dollar against the Norwegian Krone, Brazilian Real and British Pound compared to the same period last year.

Depreciation and amortization. Depreciation and amortization expense decreased for 2017 compared to 2016, primarily due to:

- a decrease of $2.6 million due to an increase in the expected useful life of the Petrojarl I FPSO unit, effective January 1, 2017, as a result of an increase in corrective maintenance and replaced equipment from the upgrades of the unit; and
- a decrease of $2.4 million mainly due to a write-down of the Rio das Ostras FPSO unit during 2017 as described below.

Write-down of vessels. Write-down of vessels was $265.2 million for 2017 and consisted of (a) a $213.2 million write-down of the Petrojarl I FPSO unit due to increasing costs associated with additional upgrade work required and estimated liquidated damages to the charterer associated with the delay in the commencement of the unit's operations and (b) a $52.0 million write-down of the Rio das Ostras FPSO unit due to a change in the operating plans for the unit resulting from receiving notification from the charterer in the third quarter of 2017 that it planned to redeliver the unit upon completion of the firm charter contract in January 2018.

Restructuring Charge. Restructuring charges incurred in 2017 and 2016 relate to the reorganization of our FPSO business to create better alignment with our offshore operations resulting in a lower cost organization going forward.

Shuttle Tanker Segment

As at December 31, 2017, our shuttle tanker fleet consisted of 30 vessels that operate under fixed-rate CoAs, time charters and bareboat charters, one shuttle tanker that commenced operations under a fixed-rate CoA in the East Coast of Canada in January 2018, five shuttle tanker newbuildings (one of which delivered in March 2018) and the HiLoad DP unit (which was in lay-up as at December 31, 2017). Of these 37 shuttle tankers, six were owned through 50%-owned subsidiaries and three were chartered-in. The remaining vessels were owned 100% by us.

The following table presents the shuttle tanker segment’s operating results for 2017 and 2016, and compares its net revenues (which is a non-GAAP financial measure) for 2017 and 2016, to revenues, the most directly comparable GAAP financial measure, for the same years. The following table also provides a summary of the changes in calendar-ship-days by owned and chartered-in vessels for the shuttle tanker segment:

	Year Ended December 31,		
(in thousands of U.S. Dollars, except calendar-ship-days and percentages)	2017	2016	% Change
Revenues	536,852	509,596	5.3
Voyage expenses	(80,964)	(62,846)	28.8
Net revenues	455,888	446,750	2.0
Vessel operating expenses	(129,517)	(123,950)	4.5
Time-charter hire expenses	(62,899)	(62,511)	0.6
Depreciation and amortization	(125,648)	(122,822)	2.3
General and administrative [(1)]	(17,425)	(10,160)	71.5
(Write-down) and gain (loss) on sale of vessels	(51,741)	4,554	(1,236.2)
Restructuring charge	(210)	(205)	2.4
Income from vessel operations	68,448	131,656	(48.0)
Calendar-Ship-Days			
Owned Vessels	10,322	10,599	(2.6)
Chartered-in Vessels	1,248	1,314	(5.0)

Total	11,570	11,913	(2.9)

(1)Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to the shuttle tanker segment based on estimated use of corporate resources). See the discussion under "Other Operating Results" below.

The average size of our owned shuttle tanker fleet decreased in 2017, compared to 2016, primarily due to the sale of the Navion Torinita, the Navion Europa and the Navion Marita shuttle tankers in January 2016, November 2016 and November 2017, respectively, partially offset by the delivery of two newbuilding shuttle tankers in late-2017. Five shuttle tanker newbuildings have been excluded from calendar-ship-days as these vessels were not yet delivered to us as at December 31, 2017.

Net revenues. Net revenues increased for 2017 compared to 2016, primarily due to:

- an increase of $11.6 million primarily due to an increase in revenues in our CoA fleet mainly as a result of higher fleet utilization and higher average rates;

- an increase of $9.9 million primarily due to an increase in project revenues, as a result of providing offloading services to Statoil for the Gina Krog field as an interim measure until the start-up of the Randgrid FSO in October 2017; and
- an increase of $5.1 million due to the Petroatlantic and Petronordic shuttle tankers commencing time-charter-out contracts in April 2017 after converting from their respective bareboat charters;

partially offset by

- a decrease of $6.0 million due to one vessel acting as a substitute for one of our FSO units during 2016;
- a decrease of $4.6 million due to lower average rates and fewer opportunities to trade excess shuttle tanker capacity in the conventional tanker spot market;
- a decrease of $4.4 million due to the redelivery of one vessel to us in June 2016 as it completed its time-charter-out agreement; and
- a decrease of $2.5 million mainly due to voyage expenses associated with the delivery and subsequent voyage to the East Coast of Canada for the Beothuk Spirit and Norse Spirit shuttle tanker newbuildings.

Vessel operating expenses. Vessel operating expenses increased for 2017 compared to 2016, primarily due to:

- an increase of $7.5 million due to repair and maintenance expenses on the Nordic Brasilia and Nordic Rio following the re-delivery of the vessels from their bareboat charter contracts during 2017;
- an increase of $6.0 million due to the Petroatlantic and Petronordic shuttle tankers commencing time-charter-out contracts in April 2017 after converting from their respective bareboat charters; and
- an increase of $3.4 million due to costs associated with the delivery and commencement of operations of the Beothuk Spirit and Norse Spirit shuttle tanker newbuildings;

partially offset by

- a decrease of $7.0 million mainly due to the timing of repairs and maintenance expenses;
- a decrease of $2.7 million due to the sale of one vessel in November 2016; and
- a decrease of $2.3 million due to a decrease in crew costs relating to a change in crew composition.

(Write-down) and gain on sale of vessels. Write-down of vessels for 2017 primarily relates to (a) a $26.3 million write-down of the HiLoad DP unit as result of a change in expectations for the future opportunities of the unit, (b) a $10.8 million write-down of the Nordic Rio shuttle tanker and a $9.3 million write-down of the Nordic Brasilia shuttle tanker as a result of a change in the operating plans for these vessels due to the redelivery of these vessels after completing their bareboat charter contracts in July 2017 and (c) a $5.1 million write-down of the Navion Marita shuttle tanker as a result of the expected sale of the vessel.

The (write-down) and gain on sale of vessels for 2016 consisted of gains on the sales of vessels of $6.7 million partially offset by a write-down of a vessel of $2.1 million. During 2016, we sold a 1992-built shuttle tanker, the Navion Torinita, for net proceeds of $5.0 million, which was the approximate carrying value of the vessel at the time of sale, and sold a 1995-built shuttle tanker, the Navion Europa, for net proceeds of $14.4 million, for which we recorded a gain on sale of $6.8 million in a 67%-owned subsidiary. During 2016, we recorded a $2.1 million write-down of the Navion Marita shuttle tanker as a result of fewer opportunities to trade the vessel in the spot conventional tanker market.

FSO Segment

As at December 31, 2017, our FSO fleet consisted of six units that operate under fixed-rate time charters or fixed-rate bareboat charters, for which our ownership interests range from 89% to 100%. The Randgrid FSO unit completed its conversion from a shuttle tanker in June 2017 and commenced operations in early-October 2017 at the Gina Krog oil and gas field located in the North Sea, under a three-year time-charter contract, which includes 12 additional one-year extension options. The Navion Saga FSO unit was sold in October 2017.

The following table presents the FSO segment's operating results for 2017 and 2016, and compares its net revenues (which is a non-GAAP financial measure) for 2017 and 2016, to revenues, the most directly comparable GAAP financial measure, for the same years. The following table also provides a summary of the changes in calendar-ship-days for the FSO segment:

(in thousands of U.S. Dollars, except calendar-ship-days and percentages)	Year Ended December 31, 2017	2016	% Change
Revenues	66,901	54,440	22.9
Voyage expenses	(1,172)	(1,517)	(22.7)
Net revenues	65,729	52,923	24.2
Vessel operating expenses	(25,241)	(23,167)	9.0
Depreciation and amortization	(19,406)	(9,311)	108.4
General and administrative [(1)]	(1,864)	(836)	123.0
(Write-down) and gain on sale of vessel	(1,108)	(983)	12.7
Income from vessel operations	18,110	18,626	(2.8)
Calendar-Ship-Days			
Owned Vessels	2,468	2,562	(3.7)

(1)Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to the FSO segment based on estimated use of corporate resources). See the discussion under "Other Operating Results" below.

The average number of our FSO units decreased for 2017 compared to 2016, due to the sale of the Navion Saga FSO unit in October 2017.

Net revenues. Net revenues increased for 2017 compared to 2016, primarily due to:

- an increase of $22.7 million due to the Randgrid FSO unit commencing operations in early-October 2017; and
- an increase of $2.3 million due to the recognition of reimbursable costs relating to the Apollo Spirit FSO unit dry docking during the third quarter of 2016 (this revenue is partially offset by an increase in depreciation and amortization expense);

partially offset by

- a decrease of $12.0 million due to the lay-up of the Navion Saga FSO unit in October 2016 until its sale in October 2017.

Vessel operating expenses. Vessel operating expenses increased for 2017 compared to 2016, primarily due to:

- an increase of $4.5 million due to the Randgrid FSO unit commencing operations in early-October 2017; and
- an increase of $1.5 million due to higher repair and maintenance costs on the Falcon Spirit FSO unit;

partially offset by

- a decrease of $5.0 million due to the redelivery and subsequent lay-up of the Navion Saga FSO unit in October 2016.

Depreciation and amortization. Depreciation and amortization expense increased for 2017 compared to 2016, primarily due to:

- an increase of $9.1 million due to the Randgrid FSO unit commencing operations in early-October 2017; and
- an increase of $1.7 million due to the Apollo Spirit FSO unit dry docking during the third quarter of 2016.

UMS Segment

As at December 31, 2017, our UMS fleet consisted of one unit, the Arendal Spirit UMS, in which we own a 100% interest and which was in lay-up as at December 31, 2017.

The Arendal Spirit UMS began its three-year charter contract with Petroleo Netherlands B.V. on June 7, 2015. In mid-April 2016, during the process of lifting off the gangway connecting the Arendal Spirit UMS to an FPSO unit, the gangway of the Arendal Spirit UMS suffered damage. During the gangway replacement, the Arendal Spirit UMS was declared off-hire. The gangway was replaced in mid-June 2016 and the Arendal Spirit UMS was declared on-hire in early-July 2016. In early November 2016, the unit experienced an operational incident relating to the dynamic positioning system and, as a result, Petroleo Netherlands B.V. suspended its charter hire payments since November 6, 2016 pending the completion of its operational review resulting from this incident. In late-April 2017, Petroleo Netherlands B.V. notified our subsidiary, Logitel Offshore Norway AS, that Petroleo Netherlands B.V. was terminating the charter contract for the Arendal Spirit UMS and would not pay the charter hire payments from November 2016. We have disputed the grounds for termination and have initiated a claim for unpaid standby fees and damages for wrongful termination of the time-charter contract.

The following table presents the UMS segment’s operating results and calendar-ship-days for 2017 and 2016.

	Year Ended December 31,		
(in thousands of U.S. Dollars, except calendar-ship-days and percentages)	2017	2016	% Change
Revenues	4,236	34,433	(87.7)
Voyage expenses	(1,152)	—	100.0
Vessel operating expenses	(33,656)	(32,888)	2.3
Depreciation and amortization	(6,566)	(6,660)	(1.4)
General and administrative (1)	(5,068)	(5,495)	(7.8)
Write-down of vessels	—	(43,650)	(100.0)
Restructuring charges	(2,004)	—	100.0
Loss from vessel operations	(44,210)	(54,260)	(18.5)
Calendar-Ship-Days			
Owned Vessels	365	366	(0.3)

(1)Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to the UMS segment based on estimated use of corporate resources). See the discussion under "Other Operating Results" below.

Revenues. Revenues decreased for 2017 compared to 2016, due to the charterer not paying charter hire payments since early-November 2016. The charter contract was subsequently terminated in April 2017 and the remaining deferred revenue of $3.9 million relating to the charter contract was recognized during 2017. The Arendal Spirit UMS was off-hire from mid-April 2016 until early-July 2016 due to damage suffered to the gangway of the unit.

Voyage expenses. Voyage expenses for 2017 included fuel costs related to the tow of the unit from Brazil to Norway, where it is currently in lay-up.

Vessel operating expenses. Vessel operating expenses increased for 2017 compared to 2016, primarily due to:

- an increase of $4.3 million due to the net write-off of deferred operating expenses upon the termination of the Arendal Spirit UMS charter contract in April 2017; and
- an increase of $3.5 million due to towage costs to bring the Arendal Spirit UMS into lay-up from Brazil to Norway during the fourth quarter of 2017;

partially offset by

- a decrease of $6.8 million mainly due to lower repairs and maintenance.

Write-down of vessels. Write-down of vessels for 2016 consists of the write-downs relating to the cancellation of two UMS newbuilding contracts in June 2016.

Restructuring charges. Restructuring charges for 2017 relate to crew and onshore staff severance costs relating to the termination of the charter contract of the Arendal Spirit UMS and the unit proceeding to lay-up.

Towage and Offshore Installation Vessels Segment

As at December 31, 2017, our towage and offshore installation fleet consisted of nine long-distance towage and offshore installation vessels and one long-distance towage and offshore installation vessel newbuilding which delivered in February 2018. Two of the vessels were in lay-up as at December 31, 2017. We own a 100% interest in each of the vessels in our towage fleet.

The following table presents the towage and offshore installation vessels segment's operating results for 2017 and 2016, and compares its net revenues (which is a non-GAAP financial measure) for 2017 and 2016, to revenues, the most directly comparable GAAP financial measure, for the same years. The following table also provides a summary of the changes in calendar-ship-days by owned and chartered-in vessels for the towage and offshore installation vessels segment.

(in thousands of U.S. Dollars, except calendar-ship-days and percentages)	Year Ended December 31, 2017	2016	% Change
Revenues	38,771	37,952	2.2
Voyage expenses	(17,727)	(15,024)	18.0
Net revenues	21,044	22,928	(8.2)
Vessel operating expenses	(21,074)	(17,524)	20.3
Time-charter hire expenses	(925)	—	100.0
Depreciation and amortization	(15,578)	(12,020)	29.6
General and administrative [1]	(4,486)	(3,307)	35.7
Loss from vessel operations	(21,019)	(9,923)	111.8
Calendar-Ship-Days			
Owned Vessels	2,839	2,307	23.1
Chartered-in Vessels	52	—	100.0
Total	2,891	2,307	25.3

(1)Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to the towage and offshore installation vessels segment based on estimated use of corporate resources). See the discussion under “Other Operating Results” below.

The average number of our towage and offshore installation vessels increased for 2017 compared to 2016, due to the delivery of three newbuilding vessels, the ALP Striker, the ALP Defender, and the ALP Sweeper, in September 2016, June 2017, and October 2017, respectively.

Net revenues. Net revenues decreased for 2017 compared to 2016, mainly due to lower utilization for the towage vessel fleet as a result of lower demand in the offshore market, partially offset by an increase in the fleet size.

Vessel operating expenses and depreciation and amortization. Vessel operating expenses and depreciation and amortization increased for 2017 compared to 2016, mainly due to the delivery of the ALP Striker, the ALP Defender, and the ALP Sweeper, in September 2016, June 2017, and October 2017, respectively.

Conventional Tanker Segment

As at December 31, 2017, our conventional tanker fleet consisted of two in-chartered conventional tankers. Both vessels were trading in the spot conventional tanker market, as at December 31, 2017.

The following table presents the conventional tanker segment’s operating results for 2017 and 2016, and compares its net revenues (which is a non-GAAP financial measure) for 2017 and 2016, to revenues, the most directly comparable GAAP financial measure, for the same years. The following table also provides a summary of the changes in calendar-ship-days by owned and chartered in vessels for the conventional tanker segment.

(in thousands of U.S. Dollars, except calendar-ship-days and percentages)	Year Ended December 31, 2017	2016	% Change
Revenues	14,022	20,746	(32.4)
Voyage expenses	(359)	(1,363)	(73.7)
Net revenues	13,663	19,383	(29.5)
Vessel operating recoveries (expenses)	10	(1,566)	(100.6)
Time-charter hire expenses	(16,491)	(12,974)	27.1
General and administrative[1]	(360)	(353)	2.0
(Loss) income from vessel operations	(3,178)	4,490	(170.8)
Calendar-Ship-Days			
Owned Vessels	—	160	(100.0)
Chartered-in Vessels	730	572	27.6
Total	730	732	(0.3)

(1)Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to the conventional tanker segment based on estimated use of corporate resources). See the discussion under “Other Operating Results” below.

The average number of our owned conventional tankers decreased for 2017 compared to 2016, due to the sales of the Kilimanjaro Spirit and the Fuji Spirit conventional tankers in March 2016, which were subsequently renamed Blue Pride and Blue Power, respectively, by the new owners.

The average number of our chartered-in conventional tankers increased in 2017 compared to 2016, due to the in-chartering of the Blue Pride and Blue Power conventional tankers in March 2016 for three years.

Net revenues. Net revenues decreased for 2017 compared to 2016, primarily due to a $4.0 million termination fee received from Teekay Corporation for the early termination of the time-charter-out contract of the Kilimanjaro Spirit in March 2016.

Vessel operating expenses. Vessel operating expenses decreased for 2017 compared to 2016, mainly due to the sale of the Kilimanjaro Spirit and the Fuji Spirit conventional tankers in March 2016, our two remaining owned conventional tankers.

Time-charter hire expense. Time-charter hire expense increased for 2017 compared to 2016, due to the in-chartering of the Blue Pride and the Blue Power conventional tankers from March 2016.

Other Operating Results

General and administrative. General and administrative expenses increased to $62.2 million for 2017, compared to $56.1 million for 2016. General and administrative expenses increased mainly due to higher business development fees relating to our FPSO segment, the Randgrid FSO unit commencing operations in early-October 2017, the delivery of the Beothuk Spirit and Norse Spirit in late-2017, and costs associated with the Brookfield Transaction, partially offset by lower management fees relating to the FPSO and shuttle tanker segments primarily from our cost saving initiatives and lower expenses as a result of the redelivery and lay-up of the Petrojarl Varg FPSO unit in August 2016.

Interest expense. Interest expense increased to $154.9 million for 2017, compared to $140.6 million for 2016, primarily due to:

- an increase of $13.4 million due to an increase in the weighted-average interest rates on our long-term debt;
- an increase of $2.8 million due to drawdowns on debt facilities following the delivery of the Randgrid FSO unit, the Beothuk Spirit and the Norse Spirit shuttle tankers, and the ALP Defender and ALP Sweeper towage and offshore installation vessels during 2017;
- an increase of $2.3 million due to accretion expense on the $200 million Brookfield Promissory Note;
- an increase of $2.1 million due to non-cash guarantee fees to Teekay Corporation associated with the long-term financing for the East Coast of Canada shuttle tanker newbuildings and certain of our interest rate swaps and cross currency swaps commencing during the second quarter of 2016, which guarantees were terminated as part of the Brookfield Transaction; and
- an increase of $2.0 million due to the ineffective portion of the unrealized loss, and the reclassification of the realized loss from accumulated other comprehensive loss to interest expense, on interest rate swaps designated as cash flow hedges relating to the towage and offshore installation vessels segment;

partially offset by

- a decrease of $4.8 million due to interest expense incurred relating to costs associated with the delay in the delivery of a UMS newbuilding in the first and second quarters of 2016 up until its construction contract cancellation in late-June 2016; and

- a decrease of $3.6 million due to decreases in our total debt balance.

Realized and unrealized loss on derivative instruments. Net realized and unrealized losses on non-designated derivative instruments were $42.9 million for 2017 compared to $20.3 million for 2016. These totals are comprised of net losses on interest rate swaps of $45.2 million in 2017 compared to $22.9 million in 2016 and net gains on foreign currency forward contracts of $2.3 million in 2017 compared to $2.6 million in 2016.

During 2017 and 2016, we had interest rate swap agreements with aggregate average outstanding notional amounts of approximately $1.8 billion and $2.1 billion, respectively, and average fixed rates of approximately 3.4% and 3.3%, respectively. Short-term variable benchmark interest rates during 2017 and 2016 were generally 1.8% or less and 1.3% or less, respectively, and as such, we incurred a realized loss of $78.3 million and $52.8 million during 2017 and 2016, respectively, under the interest rate swap agreements. The increase in realized loss was also due to settlement fees associated with early terminations of certain interest rate swaps during 2017. We also recognized a $3.2 million increase in unrealized gains on interest rate swaps mainly due to long-term LIBOR benchmark rates increasing more during 2017 compared to during 2016.

During 2017 and 2016, we were committed to foreign currency forward contracts to hedge portions of our forecasted expenditures in NOK, Euro and the Singapore Dollar, which incurred a realized gain of $0.9 million and a realized loss of $7.2 million during 2017 and 2016, respectively. We also recognized a $8.3 million decrease in the unrealized gain on foreign exchange forward contracts mainly due to lower average notional balances on the forward contracts during 2017 compared to 2016.

Please see Item 5 - Critical Accounting Estimates: Valuation of Derivative Instruments, which explains how our derivative instruments are valued, including the significant factors and uncertainties in determining the estimated fair value and why changes in these factors result in material variances in realized and unrealized losses on derivative instruments.

Equity income. Equity income was $14.4 million for 2017 compared to $17.9 million for 2016. The decrease in equity income was primarily due to an increase in the unrealized loss on derivative instruments relating to our investment in the Itajai and Libra FPSO joint ventures, partially offset by the commencement of operations of the Libra FPSO unit in late-2017.

Foreign currency exchange loss. Foreign currency exchange loss was $14.0 million for 2017, compared to $14.8 million for 2016. Our foreign currency exchange loss is due primarily to the relevant period-end revaluation of NOK-denominated monetary assets and liabilities for financial reporting purposes and the realized and unrealized gain and loss on our cross currency swaps. Gains on Norwegian Krone-denominated net monetary liabilities reflect a stronger U.S. Dollar against the NOK on the date of revaluation or settlement compared to the rate in effect at the beginning of the period. Losses on Norwegian Krone-denominated net monetary liabilities reflect a weaker U.S. Dollar against the Norwegian Krone on the date of revaluation or settlement compared to the rate in effect at the beginning of the period. There were additional realized and unrealized foreign exchange losses of $9.5 million for 2017 (2016 - losses of $8.8 million) on all other monetary assets and liabilities.

For 2017, foreign currency exchange loss includes realized losses of $84.2 million (2016 - losses of $53.5 million) and unrealized gains of $91.9 million (2016 - gains of $46.1 million) on cross currency swaps. The realized losses and the unrealized gains relating to the cross currency swaps during 2017 were impacted by the settlement of certain cross currency swaps related to the repurchase of certain of our NOK bonds in 2017. There were additional unrealized losses of $79.8 million (2016 - losses of $39.9 million), on the revaluation of the NOK-denominated debt.

During 2017, NOK 1,220 million of our senior unsecured bonds were repaid resulting in a realized foreign currency exchange gain of $67.7 million on the repayment of the bonds and a $73.4 million realized loss on the settlement of the associated cross currency swaps.

During 2016, NOK 500 million of our senior unsecured bonds matured and NOK 180 million of our senior unsecured bonds were repaid resulting in realized foreign currency exchange gains of $32.6 million and $8.6 million, respectively, on the repayment of the bonds and $32.6 million and $8.6 million realized losses, respectively, on the maturity or partial maturity of the associated cross currency swaps.

Other income (expense) - net. Other income (expense) - net was $14.2 million for 2017, compared to ($21.0) million for 2016. The increase in other income for 2017, compared to expense in 2016, is primarily due to:

- an increase of $21.4 million due to the cancellation of the two UMS newbuilding construction contracts during 2016, resulting in the recognition of an expense relating to estimated damages of $38.0 million, partially offset by a $14.5 million gain associated with the extinguishment of contingent liabilities relating to the UMS newbuildings and a $2.1 million gain relating to the reassessment of a contingent liability fair value associated with the Arendal Spirit UMS; and
- an increase of $15.0 million due to a partial reversal of a previously accrued contingent liability associated with the estimated damages from the cancellation of the UMS construction contracts, partially offset by a settlement entered into between CeFront and certain subsidiaries of ours in 2017 to settle certain outstanding claims against us.

Income tax recovery (expense). Income tax recovery (expense) was $0.1 million for 2017 compared to ($8.8) million for 2016.

The income tax recovery of $0.1 million for 2017 was mainly due to a deferred tax recovery due to an increase in our future income assumptions of our shuttle tanker fleet partially offset by a current income tax expense for the Voyageur Spirit FPSO unit due to expected taxable income.

The income tax expense of $8.8 million for 2016 was mainly due to an increase in deferred tax expense due to an increase in our valuation allowance on certain tax assets associated with changes in our redeployment assumptions given the sustained low oil price, an income tax accrual for the Voyageur Spirit FPSO unit during 2016 due to an expected taxable income as we fully utilized our U.K. losses carried forward and an estimated tax liability relating to our Singapore and towage entities.

Liquidity and Capital Resources

Liquidity and Cash Needs

Our business model is to employ our vessels on fixed-rate contracts with major oil companies, typically with terms between three and ten years. Our near-to-medium term business strategy is primarily to focus on extending contracts and redeploying existing assets on long-term charters, repaying or refinancing scheduled debt obligations and pursuing additional growth projects. Despite the weakness experienced in the global energy and capital markets, our operating cash flows prior to changes in non-cash working capital items relating to operating activities remain stable, supported by a large and well-diversified portfolio of fee-based contracts, which primarily consist of medium-to-long-term contracts with high quality counterparties. Based on upcoming capital requirements for our committed growth projects and scheduled debt repayment obligations, coupled with uncertainty regarding how long it will take for the energy and master limited partnership capital markets to normalize, we believe it is in the best interests of our common unitholders to conserve more of our internally generated cash flows to fund these projects and to reduce debt levels

In July 2018, we issued, in a U.S. private placement, a total of $700.0 million of five-year senior unsecured bonds that mature in July 2023 and used a portion of the net proceeds from the issuance to (a) repurchase $225.2 million of the $300.0 million aggregate principal of our outstanding five-year 6.0% senior unsecured bonds maturing in 2019, (b) repurchase NOK 914 million of the NOK 1,000 million aggregate principal of our outstanding senior unsecured NOK bonds maturing in 2019 and a portion of the associated cross currency swap and (c) repay at par the outstanding $200.0 million Brookfield Promissory Note maturing in 2022 along with an associated $12.0 million early termination fee. Brookfield purchased $500.0 million of the new bonds.

In January 2018, we issued Series E Preferred Units in a public offering for net proceeds of $116.0 million, which we used for general corporate purposes, which included funding installment payments on newbuilding and upgrade projects and debt repayments.

As at December 31, 2018, our total consolidated cash and cash equivalents were $225.0 million, compared to $221.9 million as at December 31, 2017. Our total liquidity, defined as cash, cash equivalents and undrawn long-term borrowings, was $225.0 million as at December 31, 2018, compared to $221.9 million as at December 31, 2017.

As at December 31, 2018, we had a working capital deficit of $487.6 million, compared to a working capital deficit of $540.5 million as at December 31, 2017. Accounts receivable and other current assets decreased mainly due to the timing of billings and collections. Accounts payable and accrued liabilities decreased mainly due to the timing of expenses related to our committed newbuildings and upgrade projects and vendor payments and the settlement of certain claims during 2018. The current net due to affiliates balance increased mainly due to an unsecured revolving credit facility provided by Brookfield and Teekay Corporation becoming due within 12 months during 2018. The current portion of long-term debt decreased mainly due to the refinancing of one revolving credit facility and one term loan in January 2018 and April 2018, respectively, the partial prepayment of the Arendal Spirit UMS term loan upon extension in August 2018, and the timing of debt repayments during 2018, partially offset by the remaining outstanding principal of our 6% five-year senior unsecured bonds maturing in July 2019. The current portion of derivative instruments liabilities decreased mainly due to the partial termination of our cross currency swaps associated with the repurchase of a portion of our NOK-denominated bonds in July 2018.

Our primary liquidity needs for 2019 are to pay existing, committed capital expenditures, to make scheduled repayments of debt, to pay debt service costs, to make quarterly distributions on outstanding preferred units, to pay operating expenses and dry docking expenditures, to fund general working capital requirements, to settle claims and potential claims against us and to manage our working capital deficit. As at December 31, 2018, our total future contractual obligations for vessels and newbuildings, were estimated to be $786.1 million, consisting of $306.6 million (2019), $402.0 million (2020) and $77.5 million (2021) related to six shuttle tanker newbuildings. During 2018 we secured a debt facility providing total borrowings of up to $60.5 million for the newbuilding payments, of which $40.4 million was undrawn as at December 31, 2018. We expect to secure additional long-term debt financing related to these shuttle tanker newbuildings.

Primarily as a result of the working capital deficit and committed capital expenditures, over the one-year period following the issuance of our 2018 consolidated financial statements, we will need to obtain additional sources of financing, in addition to amounts generated from operations, to meet our liquidity needs and our minimum liquidity requirements under our financial covenants. Additional potential sources of financing include refinancing debt facilities, increasing amounts available under existing debt facilities and entering into new debt facilities, including long-term debt financing related to the six shuttle tanker newbuildings ordered. We are actively pursuing the funding alternatives described above, which we consider probable of completion based on our history of being able to raise and refinance loan facilities. We are in various stages of completion on these matters.
Our revolving credit facilities and term loans are described in Item 18 – Financial Statements: Note 8 – Long-Term Debt. Certain of our revolving credit facilities, term loans and bonds contain covenants, debt-service coverage ratio (or DSCR) requirements and other restrictions typical of debt financing secured by vessels that restrict the ship-owning subsidiaries from, among other things: incurring or guaranteeing indebtedness; changing ownership or structure, including mergers, consolidations, liquidations and dissolutions; paying dividends or distributions if we are in default or do not meet minimum DSCR requirements; making capital expenditures in excess of specified levels; making certain negative pledges and granting certain liens; selling, transferring, assigning or conveying assets; making certain loans and investments; or entering into a new line of business. Obligations under our credit facilities are secured by certain vessels, and if we are unable to repay debt under the credit facilities, the lenders could seek to foreclose on those assets. Should we not meet these financial covenants or should we breach other covenants or DSCR requirements and not remedy the breach within an applicable cure period, if any, the lender may accelerate the repayment of the revolving credit facilities and term loans, thus having an impact on our short-term liquidity requirements and which may trigger cross-defaults or accelerations under other credit facilities. DSCR breaches can be remedied with cash cures by placing funds in escrow. We have one revolving credit facility and seven term loans

that require us to maintain vessel values to drawn principal balance ratios of a minimum range of 100% to 125%. Such requirement are assessed either on a semi-annual or annual basis, with reference to vessel valuations generally compiled by one or more agreed upon third parties. Should the ratio drop below the required amount, the lender may request us to either prepay a portion of the loan in the amount of the shortfall or provide additional collateral in the amount of the shortfall, at our option. As at December 31, 2018, these ratios were estimated to range from 122% to 414% and we were in compliance with the minimum ratios required. The vessel values used in calculating these ratios are appraised values provided by third parties where available, or are prepared by us based on second-hand sale and purchase market data. Changes in the shuttle tanker, towage and offshore installation, UMS or FPSO markets could negatively affect these ratios. As at December 31, 2018, we and our affiliates were in compliance with all covenants relating to the credit facilities and consolidated long-term debt.

The passage of climate control legislation or other regulatory initiatives that restrict emissions of greenhouse gases could have a significant financial and operational impact on our business, which we cannot predict with certainty at this time. Such regulatory measures could increase our costs related to operating and maintaining our vessels and require us to install new emission controls, acquire allowances or pay taxes related to our greenhouse gas emissions, or administer and manage a greenhouse gas emissions program. In addition, increased regulation of greenhouse gases may, in the long term, lead to reduced demand for oil and reduced demand for our services.

Cash Flows

The following table summarizes our sources and uses of cash for the periods presented:

	Year Ended December 31,		
(in thousands of U.S. Dollars)	2018	2017	2016
Net cash flow from operating activities	280,643	305,200	396,473
Net cash flow (used for) from financing activities	(121,338)	142,947	(93,415)
Net cash flow used for investing activities	(176,019)	(540,140)	(279,764)

Operating Cash Flows

Net cash flow from operating activities decreased to $280.6 million for 2018, from $305.2 million for 2017, primarily due to a decrease from changes in non-cash working capital items; reduced charter rates earned on two of our FPSO units related to charter contract extensions; and higher interest expense due to the refinancing of certain of our debt facilities in late-2017 and 2018 and the delivery of vessel newbuildings, upgrades and conversions in late-2017 and early-2018; partially offset by a settlement received in 2018 in relation to the previously-terminated charter contracts of the HiLoad DP unit and Arendal Spirit UMS; the commencement of operations of the Randgrid FSO unit in late-2017; the commencement of operations of the Petrojarl I FPSO unit in May 2018; lower operating expenses due to the lay-up of the Arendal Spirit UMS since late-2017; lower time charter hire expense on our shuttle tanker fleet mainly due to the redelivery of the Jasmine Knutsen to its owner in January 2018; and lower repairs and maintenance expenses on our FPSO units and shuttle tanker fleet.

The decrease in non-cash working capital items for 2018 compared to 2017 is primarily due to settlements of intercompany balances with related parties and the timing of payments made to vendors, partially offset by the timing of payments received from customers.

Net cash flow from operating activities decreased to $305.2 million for 2017, from $396.5 million for 2016, primarily due to, the redelivery of the Petrojarl Varg FPSO unit, the redelivery of one shuttle tanker and one FSO unit as they completed their time-charter-out agreements during 2016; the charterer of the Arendal Spirit UMS not paying charter hire payments since November 2016 and the subsequent contract termination in April 2017; lower average rates and lower utilization from our towage fleet; the sale of two conventional tankers during 2016 which were subsequently chartered-in by us; an increase in pre-operational costs during 2017 relating to the commencement of operations of the Petrojarl I FPSO unit; an increase in expenses during 2017 relating to the delivery and positioning of two newbuilding shuttle tankers for the East Coast of Canada contract; and an increase in the realized loss on derivative instruments from the partial settlement during 2017 of certain interest rate swaps; partially offset by the commencement of operations of the Randgrid FSO unit in late-2017; higher average rates and higher utilization from our shuttle tanker fleet during 2017; and lower repairs and maintenance expenses on our FPSO units during 2017.

The decrease in non-cash working capital items for 2017 compared to 2016 is primarily due to the timing of payments received from customers; partially offset by the timing of settlements of intercompany balances with related parties.

For a further discussion of changes in income statement items described above for our six reportable segments, please read “Results of Operations”.

Financing Cash Flows

We use our revolving credit facilities to finance capital expenditures and for general corporate purposes. Occasionally, we will do this until longer-term financing is obtained, at which time we typically use all or a portion of the proceeds from the longer-term financings to prepay outstanding amounts under the revolving credit facilities. Our proceeds from long-term debt, net of debt issuance costs and prepayments of long-term debt, were $263.1 million in 2018, $486.1 million in 2017 and $246.8 million in 2016.

Net proceeds from the issuance of long-term debt for the year ended December 31, 2018, mainly related to the issuance of $700.0 million five-year 8.5% senior unsecured bonds, net of the repurchase of a portion of our existing bonds, the refinancing of two debt facilities and one revolving debt facility, the drawdown of two existing debt facilities and the drawdown of two new debt facilities. These proceeds were used primarily to fund installment payments on the six current shuttle tanker newbuildings, to fund the final installment payment on the Dorset Spirit shuttle tanker newbuilding constructed for the East Coast of Canada contract, the final installment payment on the ALP Keeper towage and offshore installation vessel, the Petrojarl I FPSO unit upgrades and to fund working capital

requirements.
Net proceeds from the issuance of long-term debt for the year ended December 31, 2017, mainly related to the issuance of $250 million in senior unsecured bonds in the Norwegian bond market, the refinancing of eight debt facilities and the drawdown of three existing debt facilities.
Net proceeds from the issuance of long-term debt for the year ended December 31, 2016, mainly related to the drawdowns of one new term loan, four existing term loans, a new $35.5 million tranche added to an existing debt facility secured by two shuttle tankers, and drawdowns on one new and two existing revolving debt facilities, partially offset by the prepayments of three revolving debt facilities.

We actively manage the maturity profile of our outstanding financing arrangements. Our scheduled repayments of long-term debt were $567.3 million in 2018, compared to $652.9 million in 2017 and $476.9 million in 2016. Repayments during 2018 mainly relate to the maturity of one term loan and one revolving debt facility. Repayments during 2017 mainly relate to the maturity of one revolving debt facility, the refinancing of four debt facilities, the repayment of eight existing debt facilities, four which were subsequently refinanced, and the repayment of a portion of an existing debt facility relating to the Randgrid FSO unit conversion upon delivery of the unit, which was reimbursed by the charterer of the unit. Repayments during 2016 are mainly due to the maturity of a NOK 500 million tranche and partial repayment of NOK 180 million of our senior unsecured bonds in January 2016 and October 2016, respectively, the maturity of an existing revolving debt facility and the repayment of a portion of an existing revolving debt facility relating to the Petrojarl Varg FPSO unit.

In March 2018, we entered into a credit agreement for an unsecured revolving credit facility provided by Brookfield and Teekay Corporation, which provides for borrowings of up to $125.0 million ($25.0 million by Teekay Corporation and $100.0 million by Brookfield). During 2018, we drew down borrowings of $125.0 million related to this facility. These proceeds were used primarily to fund working capital requirements.

In January 2018, we issued 4.8 million 8.875% Series E Preferred Units in a public offering for net proceeds of $116.0 million. We used the net proceeds from the public offering for general corporate purposes, which included funding installment payments on newbuildings and upgrade projects and debt repayments.
In 2017, as part of the Brookfield Transaction, we issued 244.0 million common units and 62.4 million common unit warrants to Brookfield for gross proceeds of $610.0 million. In addition, we issued 12.0 million common units and 3.1 million common unit warrants to Teekay Corporation for gross proceeds of $30.0 million. We used a portion of the proceeds to repurchase and subsequently cancel all outstanding Series C-1 and D Preferred Units and the remainder for general corporate purposes, mainly for the funding of existing newbuilding installments and capital conversion and upgrade projects.

During 2016, we issued 5.5 million common units under our continuous offering program for net proceeds of approximately $31.0 million, 22.0 million common units in a private placement for net proceeds of approximately $99.5 million and 4,000,000 10.50% Series D Preferred Units to a group of investors for net proceeds of approximately $97.2 million. The Series D investors also received 4,500,000 common unit warrants with an exercise price of $4.55 per unit and 2,250,000 common unit warrants with an exercise price of $6.05 per unit which exercise price was reduced to $4.55 per unit in September 2017 in connection with the repurchase of our outstanding Series C-1 and D Preferred Units as part of the Brookfield Transaction. The net proceeds from the issuance of these equity securities were used for general corporate purposes including the funding of existing newbuilding installments and capital conversion and upgrade projects.

Cash distributions paid to our common and preferred unitholders and our general partner totaled $46.7 million in 2018, $60.6 million in 2017 and $78.6 million in 2016. The decrease in cash distributions paid in 2018 from 2017 was mainly due to a decrease in the quarterly distribution paid on our common units effective from the third quarter of 2017 to $0.01 per common unit compared to $0.11 per common unit paid during the first and second quarters of 2017 and the repurchase and subsequent cancellation of all outstanding Series C-1 and Series D Preferred Units during the third quarter of 2017; partially offset by an increase in distributions due to the issuance of 256 million common units during the third quarter of 2017 and the issuance of the Series E Preferred Units during the first quarter of 2018.

The decrease in cash distributions paid to our common and preferred unitholders and our general partner in 2017 from 2016 was mainly due to a decrease in the quarterly distribution paid on our common units effective from the third quarter of 2017 to $0.01 per common unit compared to $0.11 per common unit paid since the fourth quarter of 2015, the repurchase and subsequent cancellation of all outstanding Series C-1 and Series D Preferred Units during the third quarter of 2017 and the issuance of 3.7 million common units for a total value of $19.4 million, as a payment-in-kind for the distributions on our Series C-1 preferred units and our common units and general partner interest held by subsidiaries of Teekay Corporation for the distributions paid during for the year ended December 31, 2017; partially offset by an increase in distributions due to the issuance of 256 million common units as part of the Brookfield Transaction in the third quarter of 2017 and 38.1 million common units, during 2016.

Subsequent to December 31, 2018, aggregate cash distributions of $8.0 million for our Series A, Series B and Series E Preferred Units relating to the fourth quarter of 2018 were declared and were paid on February 15, 2019.

Investing Cash Flows

During 2018, net cash flow used for investing activities was $176.0 million, primarily relating to $233.7 million of payments for vessels and equipment (including final upgrade costs on the Petrojarl I FPSO unit, final installment payments on the final newbuilding towage and offshore installation vessel, the final East Coast of Canada newbuilding shuttle tanker and installment payments on the six current shuttle tanker newbuildings) and a $3.0 million investment in one of our joint ventures, partially offset by $25.3 million of net cash balances acquired as part of the acquisition of management companies from Teekay Corporation, proceeds of $30.0 million from the sale of the

Navion Scandia, Navion Britannia and Stena Spirit shuttle tankers and scheduled lease payments received of $5.4 million from leasing our direct financing lease assets.

During 2017, net cash flow used for investing activities was $540.1 million, primarily relating to $533.3 million of payments for vessels and equipment (including conversion costs on the Randgrid FSO unit conversion, upgrade costs on the Petrojarl I FPSO unit and installment payments on the newbuilding towage and offshore installation vessels, the East Coast of Canada newbuilding shuttle tankers and the two Suezmax DP2 shuttle tanker newbuildings) and $25.8 million of investments in our joint ventures, partially offset by proceeds of $13.1 million from the sale of the Navion Marita shuttle tanker and Navion Saga FSO unit and scheduled lease payments received of $5.8 million from leasing our direct financing lease assets.

During 2016, net cash flow used for investing activities was $279.8 million, primarily relating to $294.6 million of expenditures for vessels and equipment (including conversion costs on the Randgrid FSO unit conversion, upgrade costs on the Petrojarl I FPSO unit, installment payments on the newbuilding towage and offshore installation vessels, partially offset by credits received relating to the Petrojarl Knarr FPSO unit), $54.9 million of investments in our joint ventures (including $58.2 million of cash investments partially offset by a $3.3 million construction credit received), partially offset by proceeds of $69.8 million from the sale of the Navion Torinita and Navion Europa shuttle tankers and the Fuji Spirit and Kilimanjaro Spirit conventional tankers.

Contractual Obligations and Contingencies

The following table summarizes our long-term contractual obligations as at December 31, 2018:

	Total	2019	2020	2021	2022	2023	Beyond 2023
	(in millions of U.S. Dollars)						
U.S. Dollar-Denominated Obligations							
Bond repayments(1)	1,024.7	74.7	—	—	250.0	700.0	—
Secured debt - scheduled repayments(1)	1,576.2	366.4	309.0	283.6	196.3	116.8	304.1
Secured debt - repayments on maturity(1)	531.3	105.3	40.0	19.4	150.0	158.0	58.6
Unsecured revolving credit facility - due to affiliates(2)	125.0	125.0	—	—	—	—	—
Chartered-in vessels (operating leases)	36.5	34.3	2.2	—	—	—	—
Newbuildings committed costs (3)	786.1	306.6	402.0	77.5	—	—	—
Norwegian Krone-Denominated Obligations							
Bond repayments (4)	10.0	10.0	—	—	—	—	—
Total contractual obligations	4,089.8	1,022.3	753.2	380.5	596.3	974.8	362.7

(1) Excludes expected interest payments for U.S. Dollar-denominated debt of $171.1 million (2019), $150.2 million (2020), $133.6 million (2021), $103.7 million (2022), $22.9 million (2023) and $27.7 million (beyond 2023). Expected interest payments are based on existing interest rates (fixed-rate loans) and LIBOR as at December 31, 2018, plus margins which ranged between 0.90% and 4.30% (variable-rate loans). The expected interest payments do not reflect the effect of related interest rate swaps that we have used as an economic hedge of certain of our variable rate debt.

(2) Consists of the repayment of the unsecured revolving credit facility provided by Brookfield and Teekay Corporation. Excludes expected interest payments of $8.7 million (2019). The expected interest payments on the revolving credit facility are based on LIBOR as at December 31, 2018, plus a margin of 5.00% per annum until March 31, 2019 and LIBOR as at December 31, 2018, plus a margin of 7.00% per annum for balances outstanding after March 31, 2019, which is payable monthly (please refer to Item 18 - Financial Statements: Note 11h).

(3) Consists of the estimated remaining payments for the acquisition of six shuttle tanker newbuildings (please refer to Item 18 – Financial Statements: Notes 14e – Commitments and Contingencies).

(4) NOK-denominated bond repayments are based on the foreign exchange rate as at December 31, 2018 and exclude nominal expected interest payments for 2019. Expected interest payments are based on NIBOR as at December 31, 2018, plus 4.25%. The expected interest payments do not reflect the effect of related cross currency swaps that we have used as an economic hedge of certain of our NOK-denominated obligations.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably likely to have, a current or future material effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Critical Accounting Estimates

We prepare our consolidated financial statements in accordance with GAAP, which requires us to make estimates in the application of our accounting policies based on our best assumptions, judgments and opinions. On a regular basis, management reviews the accounting policies, assumptions, estimates and judgments to ensure that our consolidated financial statements are presented fairly and in accordance with GAAP. However, because future events and their effects cannot be determined with certainty, actual results could differ from our assumptions and estimates and such differences could be material. Accounting estimates and assumptions discussed in this section are those that we consider to be the most critical to an understanding of our financial statements, because they inherently involve significant judgments and uncertainties. For a further description of our material accounting policies, please read Item 18 - Financial Statements: Note 1 - Summary of Significant Accounting Policies.

Revenue Recognition

Description. Each vessel charter may, depending on its terms, contain a lease component, a non-lease component or both. For those charters accounted for as an operating lease, revenues that are fixed on or prior to the commencement of the charter are recognized by the Partnership on a straight-line basis daily over the term of the charter. For a direct financing lease, the lease component of charter hire receipts is allocated to the lease receivable and voyage revenues over the term of the lease using the effective interest rate method and the non-lease element is recognized by the Partnership on a straight-line basis daily over the term of the charter.

Judgments and Uncertainties. At the inception of the charter, the classification of the lease as an operating lease or a direct financing lease may involve the use of judgment as to the determination of the lease term. Such judgment is required as the duration of certain of our FPSO and FSO charters is unknown at commencement of the charter. The charterer may have the option to extend the charter or terminate the charter early. In addition, certain charters impose penalties on the charterer if they terminate the charter early and such penalties can vary in size depending on when, during the term of the charter, the termination right is exercised. Such penalties could impact the determination of the lease term and requires the use of judgment.

Effect if Actual Results Differ from Assumptions. A different assessment of the lease term could result in an operating lease being classified as a direct financing lease or a direct financing lease being classified as an operating lease. A change in the lease classification would result in different method of revenue recognition being applied to the lease component of the charter. In addition, if we conclude that a determination of the lease term results in the inclusion of termination penalties in the minimum lease payments under the charter, this is recognized as revenue over the lease term. Conversely, a different assessment of the lease term may result in termination penalties being excluded from the minimum lease payments and thus not recognized over the lease term.
Vessel Lives and Impairment
Description. The carrying value of each of our vessels represents its original cost at the time of delivery or purchase less depreciation and impairment charges. We depreciate the original cost, less an estimated residual value, of our vessels on a straight-line basis over each vessel’s estimated useful life. We continually reassess the estimated useful life of our vessels. The carrying values of our vessels may not represent their market value at any point in time because the market prices of second-hand vessels tend to fluctuate with changes in charter rates and the cost of newbuildings. Both charter rates and newbuilding costs tend to be cyclical in nature.

We review vessels and equipment for impairment whenever events or circumstances indicate the carrying value of an asset, including the carrying value of the charter contract, if any, under which the vessel is employed, may not be recoverable. This occurs when the asset’s carrying value is greater than the future net undiscounted cash flows the asset is expected to generate over its remaining useful life. For a vessel under charter, the discounted cash flows from that vessel may exceed its market value, as market values may assume the vessel is not employed on an existing charter. If the estimated future net undiscounted cash flows of an asset exceed the asset’s carrying value, no impairment is recognized even though the fair value of the asset may be lower than its carrying value. If the estimated future net undiscounted cash flows of an asset are less than the asset’s carrying value and the fair value of the asset is less than its carrying value, the asset is written down to its fair value. Fair value is calculated as the net present value of estimated future cash flows, which, in certain circumstances, will approximate the estimated market value of the vessel.

Our business model is to employ our vessels on fixed-rate contracts with major oil companies, typically with terms between three to ten years. Consequently, while the market value of a vessel may decline below its carrying value, the carrying value of a vessel may still be recoverable based on the future net undiscounted cash flows the vessel is expected to obtain from servicing its existing and future contracts.

The following table presents by segment, the aggregate market values and carrying values of certain of our vessels that we have determined have a market value that is less than their carrying value as of December 31, 2018, except vessels operating on contracts where the remaining term is significant and the estimated future net undiscounted cash flows relating to such contracts are sufficiently greater than the carrying value of the vessels such that we consider it unlikely impairment would be recognized in the following year. Consequently, the vessels included in the following table generally include those vessels employed on single-voyage, or spot charters, as well as those vessels nearing the end of existing charters or other operational contracts. While the market values of these vessels are below their carrying values, no impairment has been recognized on any of these vessels as the estimated future net undiscounted cash flows relating to such vessels are greater than their carrying values.

We would consider the vessels reflected in the following table to be at a higher risk of future impairment. The table is disaggregated for vessels which have estimated future undiscounted cash flows that are marginally or significantly greater than their respective carrying values. Vessels with estimated future undiscounted cash flows significantly greater than their respective carrying values would not necessarily represent vessels that would likely be impaired in the following year. The recognition of impairment in the future for those vessels may primarily depend upon our decision to dispose of the vessel instead of continuing to operate it. In deciding whether to dispose of a vessel, we determine whether it is economically preferable to sell the vessel or to continue to operate it. This assessment includes an estimate of the net proceeds expected to be received if the vessel is sold in its existing condition compared to the present value of the vessel's estimated future revenue, net of operating costs. Such estimates are based on the terms of the existing charter, charter market outlook and estimated operating costs, given a vessel's type, condition and age. In addition, we typically do not dispose of a vessel that is servicing an existing customer contract. The recognition of impairment in the future may be more likely for vessels that have estimated future undiscounted cash flows marginally greater than their respective carrying value.

(in thousands of U.S. Dollars, except number of vessels)	Number of	Market Values[(1)]	Carrying Values
Reportable Segment	Vessels	$	$
FPSO Segment[(2)]	1	288,000	358,323
Towage and Offshore Installation Vessels Segment[(2)]	2	27,250	33,910
Towage and Offshore Installation Vessels Segment[(3)]	2	37,000	51,106

(1) Market values are determined using reference to second-hand market comparable values or using a depreciated replacement cost approach as at December 31, 2018. Since vessel values can be volatile, our estimates of market value may not be indicative of the current or future prices we could obtain if we sold any of the vessels. In addition, the determination of estimated market values for our FPSO units and towage and offshore installation vessels may involve considerable judgment, given the illiquidity of the second-hand markets for these types of vessels.

The estimated market value for the FPSO unit in the table above was based on second-hand market comparable values for similar units. The estimated market values for the towage and offshore installation vessels were based on second-hand market comparable values for towage and offshore installation vessels of similar age and specifications.

65

(2) Undiscounted cash flows for these vessels are significantly greater than their carrying values.
(3) Undiscounted cash flows for these vessels are marginally greater than their carrying values.

Judgments and Uncertainties. Depreciation is calculated on a straight-line basis over a vessel's estimated useful life to an estimated residual value. Shuttle tankers are depreciated using an estimated useful life of 20 years commencing the date the vessel is delivered from the shipyard, or a shorter period if regulations prevent us from operating the vessel for the estimated useful life. FPSO units are depreciated using an estimated useful life of 20 to 25 years commencing the date the unit arrives at the oil field and is in a condition that is ready to operate. Some of our FPSO units have oil field specific equipment which is depreciated over the expected life of the oil field. The estimated useful life of our FPSO units is reassessed subsequent to a major upgrade being completed. FSO units are depreciated over the estimated term of the contract or the estimated useful life of the specific unit. UMS are depreciated over an estimated useful life of 35 years commencing the date the unit arrives at the oil field and is in a condition that is ready to operate. Towage and offshore installation vessels are depreciated over an estimated useful life of 25 years commencing the date the vessel is delivered from the shipyard. However, the actual life of a vessel may be different than the estimated useful life, with a shorter actual useful life resulting in an increase in the quarterly depreciation and potentially resulting in an impairment loss. The estimated useful life of our vessels takes into account design life, commercial considerations and regulatory restrictions. Our estimates of future cash flows involve assumptions about future charter rates, vessel utilization, operating expenses, dry-docking expenditures, vessel residual values and the remaining estimated life of our vessels. Our estimated charter rates are based on rates under existing vessel contracts and market rates at which we expect we can re-charter our vessels. Our estimates of vessel utilization, including estimated off-hire time and the estimated amount of time our shuttle tankers may spend operating in the spot tanker market when not being used in their capacity as shuttle tankers, are based on historical experience and our projections of the number of future shuttle tanker voyages. Our estimates of operating expenses and dry-docking expenditures are based on historical operating and dry-docking costs and our expectations of future inflation and operating requirements. Vessel residual values are a product of a vessel's lightweight tonnage and estimated scrap rates. The remaining estimated lives of our vessels used in our estimates of future cash flows are consistent with those used in the calculation of depreciation.

Certain assumptions relating to our estimates of future cash flows are more predictable by their nature in our experience, including estimated revenue under existing contract terms, ongoing operating costs and remaining vessel life. Certain assumptions relating to our estimates of future cash flows require more discretion and are inherently less predictable, such as future charter rates beyond the firm period of existing contracts and vessel residual values, due to factors such as the volatility in vessel charter rates and vessel values. We believe that the assumptions used to estimate future cash flows of our vessels are reasonable at the time they are made. We can make no assurances, however, as to whether our estimates of future cash flows, particularly future vessel charter rates or vessel values, will be accurate.

Effect if Actual Results Differ from Assumptions. If we conclude that a vessel or equipment is impaired, we recognize a loss in an amount equal to the excess of the carrying value of the asset over its fair value at the date of impairment. The written-down amount becomes the new lower cost basis and will result in a lower annual depreciation expense than for periods before the vessel impairment.

Dry docking

Description. We dry dock each of our shuttle tankers and towage and offshore installation vessels periodically for inspection, repairs and maintenance and for any modifications to comply with industry certification or governmental requirements. We may dry dock FSO units if we desire to qualify them for shipping classification. We capitalize a substantial portion of the costs we incur during dry docking and amortize those costs on a straight-line basis over the estimated useful life of the dry dock. We immediately expense costs for routine repairs and maintenance performed during dry docking that do not improve or extend the useful lives of the assets.

Judgments and Uncertainties. Amortization of capitalized dry-dock expenditures requires us to estimate the period of the next dry docking or estimated useful life of dry-dock expenditures. While we typically dry dock each shuttle tanker and towage vessel every two and a half to five years, we may dry dock the vessels at an earlier date.

Effect if Actual Results Differ from Assumptions. A change in our estimate of the useful life of a dry dock will have a direct effect on our annual amortization of dry-docking expenditures.

Goodwill

Description. We allocate the cost of acquired companies to the identifiable tangible and intangible assets and liabilities acquired, with the remaining amount being classified as goodwill. Our future operating performance will be affected by the potential impairment charges related to goodwill. Accordingly, the allocation of the purchase price to goodwill may significantly affect our future operating results. Goodwill is not amortized, but reviewed for impairment annually or more frequently if impairment indicators arise. The process of evaluating the potential impairment of goodwill is highly subjective and requires significant judgment at many points during the analysis.

Judgments and Uncertainties. The allocation of the purchase price of acquired companies to goodwill requires management to make significant estimates and assumptions, including estimates of future cash flows expected to be generated by the acquired assets and the appropriate discount rate to value these cash flows. In addition, the process of evaluating the potential impairment of goodwill and intangible assets is highly subjective and requires significant judgment at many points during the analysis. The fair value of our reporting units was estimated based on discounted expected future cash flows using a weighted-average cost of capital rate. The estimates and assumptions regarding expected cash flows and the appropriate discount rates require considerable judgment and are based upon existing contracts, historical experience, financial forecasts and industry trends and conditions.

As of December 31, 2018, the shuttle tanker segment and the towage and offshore installation vessels segment had goodwill of $127.1 million and $2.0 million, respectively, (2017 - $127.1 million and $2.0 million, respectively) attributable to them. As of the date of this filing, we do not believe that there is a reasonable possibility that the goodwill attributable to these reporting units might be impaired within the next year. However, certain factors that impact this assessment are inherently difficult to forecast and as such we cannot provide any assurances that an impairment will or will not occur in the future. An assessment for impairment involves a number of assumptions and estimates that are based on factors that are beyond our control. These are discussed in more detail in the section entitled “Forward-Looking Statements.”

Valuation of Derivative Instruments

Description. Our risk management policies permit the use of derivative financial instruments to manage interest rate and foreign exchange risks. Changes in fair value of derivative financial instruments that are not designated as cash flow hedges for accounting purposes are recognized in earnings.

Judgments and Uncertainties. A substantial majority of the fair value of our derivative instruments and the change in fair value of our derivative instruments from period to period result from our use of interest rate swap agreements. The fair value of our derivative instruments is the estimated amount that we would receive or pay to terminate the agreements in an arm’s length transaction under normal business conditions at the reporting date, taking into account current interest rates, foreign exchange rates and the current credit worthiness of ourselves and the swap counterparties. The estimated amount is the present value of estimated future cash flows, being equal to the difference between the benchmark interest rate and the fixed rate in the interest rate swap agreement, multiplied by the notional principal amount of the interest rate swap agreement at each interest reset date.

The fair value of our interest rate swap agreements at the end of each period is most significantly impacted by the interest rate implied by the benchmark interest rate yield curve, including its relative steepness. Interest rates have experienced significant volatility in recent years in both the short-term and long-term. While the fair value of our interest rate swap agreements is typically more sensitive to changes in short-term rates, significant changes in the long-term benchmark interest rate also materially impact our interest rate swap agreements.

The fair value of our interest rate swap agreements is also impacted by changes in our specific credit risk included in the discount factor. We discount our interest rate swap agreements with reference to the credit default swap spreads of similarly rated global industrial companies and by considering any underlying collateral. The process of determining credit worthiness requires significant judgment in determining which source of credit risk information most closely matches our risk profile.

The benchmark interest rate yield curve and our specific credit risk are expected to vary over the life of the interest rate swap agreements. The larger the notional amount of the interest rate swap agreements outstanding and the longer the remaining duration of the interest rate swap agreements, the larger the impact of any variability in these factors will be on the fair value of our interest rate swaps. We economically hedge the interest rate exposure on a significant amount of our variable rate long-term debt and for long durations. As such, we have historically experienced, and we expect to continue to experience, material variations in the period-to-period fair value of our derivative instruments.

Effect if Actual Results Differ from Assumptions. Although we measure the fair value of our derivative instruments using the inputs and assumptions described above, if we were to terminate the agreements at the reporting date, the amount we would pay or receive to terminate the derivative instruments may differ from our estimate of fair value. If the estimated fair value differs from the actual termination amount, an adjustment to the carrying amount of the applicable derivative asset or liability would be recognized in earnings for the current period. Such adjustments could be material. See Item 18 – Financial Statements: Note 12 – Derivative Instruments for the effects on the change in fair

value of our derivative instruments on our consolidated statements of income.
Taxes
Description. We record a valuation allowance to reduce our deferred tax assets to the amount that is more likely than not to be realized.

Judgments and Uncertainties. The future realization of deferred tax assets depends on the existence of sufficient taxable income of the appropriate character in either the carryback or carryforward period. This analysis requires, among other things, the use of estimates and projections in determining future reversals of temporary differences, forecasts of future profitability and evaluating potential tax-planning strategies.

Effect if Actual Results Differ from Assumptions. If we determined that we were able to realize a net deferred tax asset in the future, in excess of the net recorded amount, an adjustment to the deferred tax assets would typically increase our net income (or decrease our loss) in the period such determination was made. Likewise, if we determined that we were not able to realize all or a part of our deferred tax asset in the future, an adjustment to the deferred tax assets would typically decrease our net income (or increase our loss) in the period such determination was made. As at December 31, 2018, we had a valuation allowance of $224.6 million (2017 - $85.6 million).
Item 6. Directors, Senior Management and Employees
A. Directors and Senior Management
Management of Teekay Offshore Partners L.P.

Teekay Offshore GP L.L.C., our general partner, manages our operations and activities. Unitholders generally are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operation.

Our general partner owes a fiduciary duty to our unitholders. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are expressly non-recourse to it. Whenever possible, our general partner intends to cause us to incur indebtedness or other obligations that are non-recourse to it.

The directors of our general partner oversee our operations. Our general partner has a Secretary but does not have any other officers. In February 2017, the Partnership and its wholly-owned subsidiary, Teekay Offshore Holdings L.L.C. (or Holdco), entered into a services agreement with Teekay Offshore Group Ltd. (or the Service Provider), a subsidiary of Holdco.

Pursuant to the service agreement, the Service Provider provides various service to us, including managerial services to Holdco and its operational subsidiaries, and administrative services to the Partnership. Please see Item 7- Major Unitholders and Related Party Transactions. Certain officers and employees of Teekay Corporation and its subsidiaries also provide administrative and operational services to us pursuant to services agreements.

Those individuals providing services to us or our subsidiaries may face a conflict regarding the allocation of their time between our business and the business interests of Teekay Corporation or its other affiliates. The various services agreements require the service providers to provide the services diligently and in a commercially reasonable manner.

Because certain directors of our general partner are also directors and/or officers of Teekay Corporation, Brookfield or other affiliates thereof, such directors have fiduciary duties to Teekay Corporation, Brookfield or such other affiliates that may cause them to pursue business strategies that disproportionately benefit Teekay Corporation, Brookfield or such other affiliates or which otherwise are not in our best interests.
Directors of Teekay Offshore GP L.L.C.
The following table provides information about the directors of our general partner, Teekay Offshore GP L.L.C., as at the date of this Annual Report. Directors are elected for one-year terms. The business address of each of our directors listed below is c/o 4th Floor, Belvedere Building, 69 Pitts Bay Road, Hamilton, HM 08, Bermuda. Ages of the directors and officers are as of December 31, 2018.

Name	Age	Position
Ian Craig	66	Director (1)
Kenneth Hvid	50	Director (2)
Craig Laurie	47	Director (3)
David L. Lemmon	76	Director (4)
John J. Peacock	75	Director (5)
Jim Reid	53	Director (6)
Denis Turcotte	57	Director(3)(7)
Walter Weathers	47	Director (7)
Bill Utt	61	Chairman of the Board of Directors (8)

(1) Member of Audit Committee and Conflicts Committee (Chair).
(2) Observer to Compensation Committee.
(3) Appointed on September 12, 2018, replacing David Levenson and Bradley Weismiller.
(4) Member of Audit Committee, Conflicts Committee and Compensation Committee (Chair).
(5) Member of Audit Committee (Chair) and Conflicts Committee.
(6) Observer to Audit Committee.

(7) Member of Compensation Committee and Corporate Governance Committee.
(8) Chair of the Corporate Governance Committee.

In connection with the Brookfield Transaction, Brookfield TK TOGP L.P. (or Brookfield TOGP) and Teekay Corporation amended and restated the limited liability company agreement of our general partner to set forth, among other things, the relative rights of such entities to appoint directors of the general partner, as described in Item 7. Major Unitholders and Related Party Transactions--B. Certain Relationships and Related Party Transactions--Relating to the Brookfield Transaction--General Partner Agreement.

Certain biographical information about each of these individuals is set forth below.

Ian Craig was appointed a director of our general partner in June 2017. Mr. Craig has served in various executive positions in Shell, most recently in Nigeria where he was an Executive Vice President for Sub Saharan Africa and in Russia where he was Chief Executive Officer of Sakhalin Energy, an incorporated joint venture of Gazprom, Shell, Mitsui and Mitsubishi. Prior to that, Mr. Craig was a Board member and

Technical Director of Enterprise Oil plc until its acquisition by Shell in 2002. He had earlier held executive management positions with other oil exploration and production companies including Sun Oil and BP. Since retiring in 2013, Mr. Craig has also previously served as a non-executive director of Petroceltic plc and as a Special Advisor to OMV's supervisory board.

Kenneth Hvid was appointed President and Chief Executive Officer of Teekay Corporation in February 2017 and has served as a director of our general partner since 2011, a director of Teekay Tankers Ltd since February 2017, and a director of Teekay Gas GP L.L.C. since September 2018. Mr. Hvid joined Teekay Corporation in 2000 and was responsible for leading its global procurement activities until he was promoted in 2004 to Senior Vice President, Teekay Gas Services. During that time, Mr. Hvid was involved in leading Teekay Corporation through its entry and growth in the liquefied natural gas business. He held that position until the beginning of 2006, when he was appointed President of the Teekay Navion Shuttle Tankers and Offshore division. In that role, he was responsible for Teekay Corporation's global shuttle tanker business as well as initiatives in the floating, storage and offtake business and related offshore activities. Mr. Hvid served as Teekay Corporation's Chief Strategy Officer and Executive Vice President from 2011 to 2015, as a director of Teekay GP L.L.C. from 2011 to 2015 and as President and Chief Executive Officer of Teekay Offshore Group Ltd., from 2015 to 2016. Mr. Hvid has 29 years of global shipping experience, 12 of which were spent with A.P. Moller in Copenhagen, San Francisco and Hong Kong. In 2007, Mr. Hvid joined the board of Gard P. & I. (Bermuda) Ltd.

Craig Laurie was appointed a director of our general partner in September 2018. Mr. Laurie is a Managing Partner in Brookfield's Private Equity Group overseeing Capital Markets, Finance and Planning. Mr. Laurie joined Brookfield in 1997 and has held a number of senior finance positions across the organization, including Chief Financial Officer of Brookfield Business Partners. Prior to joining Brookfield, Mr. Laurie worked in restructuring and advisory services at Deloitte. Mr. Laurie is a Chartered Professional Accountant and holds a Bachelor of Commerce from Queen's University.

David L. Lemmon has served as a director of our general partner since 2006. Mr. Lemmon served on the board of directors of Kirby Corporation, a position he held from 2006 until 2014. Mr. Lemmon also served on the board of directors of Deltic Timber Corporation from 2007 until 2017. Mr. Lemmon was the President and Chief Executive Office of Colonial Pipeline Company from 1997 until his retirement in 2006. Prior to joining Colonial Pipeline Company, he served as President of Amoco Pipeline Company for seven years, as part of a career with Amoco Corporation that spanned 32 years. Mr. Lemmon has served as a member of the board of directors of the American Petroleum Institute, the National Council of Economic Education and the Battelle Energy Advisory Committee. He has served as a member of the Northwestern University Business Advisory Committee and as a guest faculty member at Northwestern University's Kellogg Graduate School of Management.

John J. Peacock has served as a director of our general partner since 2006. Mr. Peacock retired in 2007 from Fednav Limited, a Canadian ocean-going, dry-bulk shipowning and chartering group. Joining as Fednav's Treasurer in 1979, he became Vice-President Finance in 1984 and joined the board of directors. In 1998, Mr. Peacock was appointed Executive Vice-President of Fednav and President and Chief Operating Officer of Fednav International Ltd., the Group's principal operating subsidiary. Though retired, he continues to serve as a Director. Mr. Peacock has over 40 years accounting experience, and prior to joining Fednav was a partner with Clarkson Gordon (now Ernst & Young) in Montreal, Canada.

Jim Reid was appointed a director of our general partner in September 2017. Mr. Reid is a Managing Partner and a Chief Investment Officer in Brookfield's Private Equity Group. Mr. Reid is responsible for originating, evaluating and structuring investments and financings in the energy sector and overseeing operations in Brookfield's energy segment. He established Brookfield's Calgary office in 2003 after spending several years as a Chief Financial Officer for two oil and gas exploration and production companies in Western Canada. Mr. Reid obtained his Chartered Professional

Accountant designation at PriceWaterhouseCoopers in Toronto and holds a Bachelor of Arts in Commerce from the University of Toronto.

Dennis Turcotte was appointed a director of our general partner in September 2018. Mr. Turcotte is a Managing Partner in Brookfield's Private Equity Group, responsible for business operations. Mr. Turcotte joined Brookfield's Private Equity Group in 2017, prior to which he served as a member of the Brookfield Private Equity Advisory Board for 10 years and as a member of the Brookfield Business Partners' Board of Directors from 2016 until 2017. Prior to joining Brookfield, Mr. Turcotte held several roles, including Principal with North Channel Management and Capital Partners, Chief Executive Officer of Algoma Steel, President of the Paper Group and Executive Vice President, Corporate Development and Planning with Tembec. Mr. Turcotte holds a Bachelor of Engineering from Lakehead University and an MBA from the University of Western Ontario.

Walter Weathers was appointed a director of our general partner in September 2017. Mr. Weathers is a Senior Vice President for Brookfield Asset Management, focused on private equity investments in the oil and gas sector. Prior to his current position, Mr. Weathers served in various roles within Cameron International Corporation (a company owned by Schlumberger), including Vice President of Finance, Vice President of Rig Equipment Houston, Vice President of Marketing & Strategy, and Director of Mergers & Acquisitions. Before joining Cameron, Mr. Weathers served as Vice President Finance for NATCO Group and was a principal of The Catalyst Group. Mr. Weathers holds an MBA from the University of Texas McCombs School of Business and a Bachelor of Science from the United States Naval Academy, and he is a veteran of the United States Marine Corps.

Bill Utt was appointed Chairman and a director of our general partner in June 2017. He has served as a director of Teekay Corporation since 2015 and was appointed Chairman in June 2017. In September 2018, Mr. Utt was appointed to the Board of Teekay GP L.L.P.. Mr. Utt brings over 33 years of engineering and energy industry experience to his board position. From 2006 until his retirement in 2014, he served as Chairman, President and Chief Executive Officer of KBR Inc., a global engineering, construction and services company. From 1995 to 2006, Mr. Utt served as the President and Chief Executive Officer of SUEZ Energy North America and President and Chief Executive Officer of Tractebel's North American energy businesses. Prior to 1995 he held senior management positions with CRSS, Inc., which was a developer and operator of independent power and industrial energy facilities prior to its merger with Tractebel in 1995. Mr. Utt also currently serves as a member of the Board of Directors for Brand Industrial Holdings Inc, a Clayton, Dubilier & Rice, LLC portfolio.

Our Management

Our general partner has a Secretary but does not have any other officers. On February 1, 2017, Teekay Offshore Partners L.P. and its wholly-owned subsidiary, Holdco, entered into a service agreement with the Service Provider, a subsidiary of Holdco. The following table presents certain information regarding the senior management team that is principally responsible for our operations and their positions with the Service Provider as at the date of this Annual Report:

Name	Age	Position
Ingvild Sæther	50	President and Chief Executive Officer, Teekay Offshore Group Ltd.
Jan Rune Steinsland	58	Chief Financial Officer, Teekay Offshore Group Ltd.(1)
Duncan Donaldson	39	General Counsel, Teekay Offshore Group Ltd.
Edith Robinson	54	Secretary, Teekay Offshore GP LLC

(1) Appointed September 2018, replacing interim CFO, Tim Cowan. Tim Cowan was appointed interim CFO on June 11, 2018, replacing David Wong.

Ingvild Sæther was appointed President and Chief Executive Officer of Teekay Offshore Group Ltd. in February 2017. Ms. Sæther joined Teekay Corporation in 2002, as a result of Teekay Corporation's acquisition of Navion AS from Statoil ASA. Since joining Teekay Corporation, Ms. Sæther has held management positions in Teekay Corporation's conventional tanker business until 2007, when she assumed the commercial responsibility for Teekay Corporation’s shuttle tanker activities in the North Sea, and in 2011, Ms. Sæther assumed the position of President, Teekay Offshore Logistics. Ms. Sæther has over 25 years of experience in the shipping and offshore sector and has been engaged in a number of boards and associations related to the industry.

Jan Rune Steinsland was appointed Chief Financial Officer of Teekay Offshore Group Ltd. in September 2018. Mr. Steinsland joined Teekay from Songa Offshore SE where he served as Chief Financial Officer and brings 30 years of energy and offshore industry experience. Previous assignments of Mr. Steinsland’s include serving as Chief Financial Officer at Ocean Rig and Acta Holding, as well as serving in several senior management positions at Esso Norge and Exxon Company International. Mr. Steinsland has a Lic. Oec. degree from the University of St. Gallen, Switzerland and a Norwegian CFA from the Norwegian School of Economics.

Duncan Donaldson was appointed General Counsel of Teekay Offshore Group Ltd. in January 2018. Mr. Donaldson is a United Kingdom national and has been a qualified lawyer in England and Wales since 2005. Throughout his career Mr. Donaldson has specialized in the energy, transportation and infrastructure sectors, first in private practice with Linklaters LLP in London and subsequently in a variety of legal roles within the offshore business units of the A.P. Moller-Maersk Group. Most recently Mr. Donaldson served for three years as Chief Legal Counsel, North and South America for Maersk Drilling based in Houston, Texas, during which time he was also registered as a Foreign Legal Consultant with the State Bar of Texas. Mr. Donaldson has a BA (Hons) degree from Cambridge University and completed his post-graduate legal education at Nottingham Law School.

Edith Robinson was appointed as the Secretary of our general partner in 2014 and as secretary of Teekay Offshore Group Ltd. in 2015. Ms. Robinson joined Teekay Corporation in 2014 and currently serves as an Associate General Counsel. She is also Secretary of Teekay GP L.L.C. and Teekay Tankers Ltd. Prior to joining Teekay Corporation, Ms. Robinson served as the General Counsel for a utility group in Bermuda. She has over 20 years of legal experience and is qualified to practice law in Bermuda, Ontario Canada, and England. Ms. Robinson has an MBA from Cornell University in addition to her legal qualifications.

B. Compensation

Executive Compensation

During 2018, the aggregate amount incurred by the Service Provider for compensation expenses of the individuals identified, excluding any long-term incentive plan awards issued directly by us as described below, was $1.4 million.

The amounts were paid primarily in Canadian Dollars or Norwegian Kroner, but are reported here in U.S. Dollars using an average exchange rate of 1.30 Canadian Dollars or 8.13 Norwegian Kroner for each U.S. Dollar for 2018.

Compensation of Directors

Mr. Kenneth Hvid, the President and Chief Executive Officer of Teekay Corporation and who also serves as director of our general partner, does not receive additional compensation for his service as a director of our general partner. Each of our non-employee directors receives compensation for attending meetings of the Board of Directors, as well as committee meetings. During 2018, each non-employee director, other than the Chair, received a director fee of $60,000 for the year and an award of common units with an aggregate maximum value of approximately $75,000 for the year. The Chair received a director fee of $60,000 and an additional annual fee of $47,500 for the year and an award of common units with a value of approximately $107,500 for the year. In addition, members of the audit, conflicts and corporate governance committees each received an additional committee fee of $7,500, $5,000 and $5,000 respectively for the year, and the chairs of each committee received an additional fee of $17,000, $12,000 and $10,000 respectively for the year for serving in that role. Each director was also reimbursed for out-of-pocket expenses in connection with attending meetings of the Board of Directors or committees. Each director is fully indemnified by us for actions associated with being a director to the extent permitted under Marshall Islands law.

During 2018, the 10 non-employee directors received (two of whom left the board in September 2018), in the aggregate, $812,000 in cash fees for their services as directors, plus reimbursement of their out-of-pocket expenses. During the year ended December 31, 2018, a total of 293,770 common units, with an aggregate value of $0.8 million, were granted and issued to the non-employee directors of the general partner as part of their annual compensation for 2018.

2006 Long-Term Incentive Plan

Our general partner adopted the Teekay Offshore Partners L.P. 2006 Long-Term Incentive Plan for employees and directors of and consultants to our general partner and employees and directors of and consultants to its affiliates, who perform services for us. The plan provides for the award of restricted units, phantom units, unit options, unit appreciation rights and other unit or cash-based awards. In March 2018, our general partner awarded 1,424,058 restricted units to certain employees of its affiliates who provide services to our business with a grant date fair value of $3.7 million, based on our closing common unit price on the grant date. Each restricted unit is equal in value to one of our common units plus reinvested distributions from the grant date to the vesting date. The restricted units vest evenly over a three-year period from the grant date. Any portion of a restricted unit award that is not vested on the date of a recipient's termination of service is canceled, unless their termination arises as a result of the recipient's retirement and in this case the restricted unit award will continue to vest in accordance with the vesting schedule. Upon vesting, the value of the restricted units is paid to each grantee in the form of common units or cash.

C. Board Practices

Teekay Offshore GP L.L.C., our general partner, manages our operations and activities. Unitholders generally are not entitled to elect directors of our general partner or directly or indirectly participate in our management or operation.

The Board currently consists of nine directors. Directors are appointed to serve until their successors are appointed or until they resign or are removed.

There are no service contracts between us and any of our directors providing for benefits upon termination of their employment or service.

The Board has the following four committees: Audit Committee, Conflicts Committee, Corporate Governance Committee and Compensation Committee. The membership of these committees and the function of each of the committees are described below. The Audit Committee and Conflicts Committee are currently comprised solely of independent directors, and each of the committees operates under a written charter adopted by the Board. Mr. Kenneth Hvid, an officer and employee of Teekay Corporation, is an observer on the Compensation Committee; Mr. Jim Reid, an officer and employee of Brookfield, is an observer on the Audit Committee. The committee charters for the Audit Committee, the Conflicts Committee, the Corporate Governance Committee and the Compensation Committee are available under "Investors – Teekay Offshore Partners L.P. - Governance" from the home page of our web site at www.teekay.com. During 2018, the Board held 15 meetings. All directors attended all board meetings, except for two meetings where two directors did not attend and two meetings where one director did not attend. All members of the Audit Committee, the Conflicts Committee and the Compensation Committee attended all meetings and one member of the Corporate Governance Committee did not attend one meeting.

Audit Committee. The Audit Committee of our general partner is composed of three or more directors, each of whom must meet the independence standards of the NYSE, the SEC and any other applicable laws and regulations governing independence from time to time. This committee is currently comprised of directors John J. Peacock (Chair), David L. Lemmon and Ian Craig, all independent directors. Mr. Reid is an observer to the committee. All members of the committee are financially literate and the Board has determined that Mr. Peacock qualifies as an audit committee financial expert.

The Audit Committee assists the Board in fulfilling its responsibilities for general oversight of:

- the integrity of our financial statements;
- our compliance with legal and regulatory requirements;
- the qualifications and independence of our independent auditor; and
- the performance of our internal audit function and our independent auditor.

Conflicts Committee. The Conflicts Committee of our general partner is composed of at least two directors and is currently composed of the same directors constituting the Audit Committee, being Ian Craig (Chair), David L. Lemmon and John J. Peacock. There is no observer to the committee. The members of the Conflicts Committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, and must meet the heightened NYSE and SEC director independence standards applicable to audit committee membership and certain other requirements.

The Conflicts Committee:

- reviews specific matters that the Board believes may involve conflicts of interest; and
- determines if the resolution of the conflict of interest is fair and reasonable to us.

Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders. The Board is not obligated to seek approval of the Conflicts Committee on any matter, and may determine the resolution of any conflict of interest itself.

Corporate Governance Committee. The Corporate Governance Committee of our general partner is composed of at least two directors. This committee is currently composed of directors Bill Utt (Chair), Denis Turcotte and Walter Weathers.

The Corporate Governance Committee:

- oversees the operation and effectiveness of the Board and its corporate governance; and
- develops, updates and recommends to the Board corporate governance principles and policies applicable to us and our general partner and monitors compliance with these principles and policies.

Compensation Committee. The Compensation Committee of our general partner is composed of at least two directors. This committee is currently comprised of directors David L. Lemmon (Chair), Denis Turcotte and Walter Weathers. Mr. Hvid is an observer on the Compensation Committee.

The Compensation Committee:

- discharges the responsibilities of the Board relating to compensation of the executive officers, if any, of us, our general partner, our key subsidiaries and the Board; and
- approves and evaluates compensation plans, policies and programs of us and our general partner.

D. Employees

Crewing and Staff

As of December 31, 2018, approximately 2,000 seagoing staff served on our vessels, compared to approximately 2,100 seagoing staff as of December 31, 2017 and approximately 2,200 seagoing staff as of December 31, 2016. Since January 1, 2018, certain of our subsidiaries have employed and, prior to January 1, 2018, subsidiaries of Teekay Corporation employed the crew, who serve on the vessels pursuant to agreements with the subsidiaries. As of December 31, 2018, our subsidiaries employed approximately 400 staff who served on shore in technical, commercial and administrative roles in various countries compared to approximately 53 staff as of December 31, 2017 and approximately 50 staff as of December 31, 2016. Teekay Corporation subsidiaries also provided certain on-shore advisory and administrative support to our operating subsidiaries pursuant to service agreements.

We regard attracting and retaining motivated seagoing personnel as a top priority, and offer seafarers what we believe are highly competitive employment packages and comprehensive benefits and opportunities for personal and career development, which relates to a philosophy of promoting internally.

Teekay Corporation has entered into a Collective Bargaining Agreement with the Philippine Seafarers' Union, an affiliate of the International Transport Workers' Federation (or ITF), and a Special Agreement with ITF London, which covers substantially all of the officers and seamen that operate our Bahamian-flagged vessels. Substantially all officers and seamen for the Norway-flagged vessels are covered by a collective bargaining agreement with Norwegian unions (Norwegian Maritime Officers' Association, Norwegian Union of Marine Engineers and the Norwegian Seafarers' Union). We have entered into a Collective Bargaining Agreement with Sindicato dos Trabalhadores Offshore do Brasil (or SINDITOB), which covers substantially all Brazilian resident offshore employees on board our FPSO units Rio das Ostras and Piranema Spirit. We have entered into a Collective Bargaining Agreement with Norwegian offshore unions (SAFE, Industry Energi and DSO), through its membership in Norwegian Shipowners Association (or NSA). The agreement covers substantially all of the offshore employees on board our FPSO units on the Norwegian Continental Shelf. We have entered into a Collective Bargaining Agreement with the Fish, Food and Allied Workers Union of Newfoundland and Labrador and the Canadian Merchant Service Guild in Canada. The agreement covers substantially all of the offshore employees on board our shuttle tankers operating in the East Coast of Canada. We believe our relationships with these local labor unions are good, with long-term collective bargaining agreements which demonstrate commitment from both parties.

Our commitment to training is fundamental to the development of the highest caliber of seafarers for marine operations. Teekay Corporation’s and our cadet training approach is designed to balance academic learning with hands-on training at sea. Teekay Corporation has relationships with training institutions in the Philippines and we have relationships with training institutions in Canada, Norway, Brazil and the United Kingdom. After receiving formal instruction at one of these institutions, cadet training continues on board vessels. We also have a career development plan that was devised to ensure a continuous flow of qualified officers who are trained on our vessels and familiarized with our operational standards, systems and policies. We believe that high-quality crewing and training policies will play an increasingly important role in distinguishing larger independent shipping companies that have in-house or affiliate capabilities from smaller companies that must rely on outside ship managers and crewing agents on the basis of customer service and safety.

E. Unit Ownership

The following table sets forth certain information regarding beneficial ownership, as of December 31, 2018, of our common units by all the current directors and the officer of our general partner as a group. It also includes the senior management of the Service Provider. The information is not necessarily indicative of beneficial ownership for any other purpose. Under SEC rules, a person beneficially owns any common units that the person has the right to acquire as of March 1, 2019 (60 days after December 31, 2018) through the exercise of any common unit option or other right. Unless otherwise indicated, each person has sole voting and investment power (or shares such powers with his or her spouse) with respect to the common units set forth in the following table. Information for all persons listed below is based on information delivered to us.

Identity of Person or Group	Common Units Owned	Percentage of Common Units Owned[2]	
All directors and officers as a group (13 persons)[1]	351,488	0.09	%

(1) Each director, officer and key employee beneficially owns less than 1% of the outstanding units.

(2) Excludes the 0.76% general partner interest held by our general partner, a 51%-owned subsidiary of Brookfield and 49%-owned subsidiary of Teekay Corporation.

Item 7. Major Unitholders and Related Party Transactions

A. Major Unitholders

The following table sets forth the beneficial ownership, as of December 31, 2018, of our common units by each person we know to beneficially own more than 5% of the outstanding common units. The number of common units beneficially owned by each person is determined under SEC rules and the information is not necessarily indicative of beneficial ownership for any other purpose. Under SEC rules a person beneficially owns any common units as to which the person has or shares voting or investment power. In addition, a person beneficially owns any units that the person or entity has the right to acquire as of March 1, 2019 (60 days after December 31, 2018) through the exercise of any common unit option or other right. Unless otherwise indicated, each unitholder listed below has sole voting and investment power with respect to the common units set forth in the following table:

Identity of Person or Group	Common Units Owned	Percentage of Common Units Owned
Brookfield TK TOLP L.P. [1]	244,000,000	59.5%
Teekay Corporation [1]	56,587,484	13.8%
FMR LLC [2]	32,924,307	8.0%

(1) Excludes the 0.76% general partner interest held by our general partner, a 51%-owned subsidiary of Brookfield and a 49%-owned subsidiary of Teekay Corporation.

(2) Includes sole dispositive power of FMR LLC as to 32,924,307 units. This information is based on the Schedule 13G filed by this entity with the SEC on February 13, 2019.

As of December 31, 2018, Brookfield TOGP, an affiliate of Brookfield, held a 51% interest in our general partner, and an affiliate of Teekay Corporation held a 49% interest in our general partner.

B. Certain Relationships and Related Party Transactions

Certain Relationships

Brookfield TOGP and an affiliate of Teekay Corporation currently own 51% and 49% ownership interests, respectively, in our general partner, Teekay Offshore GP L.L.C. As of December 31, 2018, Brookfield TK TOLP L.P. (or Brookfield TOLP), an affiliate of Brookfield, and Teekay Corporation held 59.5% and 13.8% of our outstanding common units, respectively.

Craig Laurie, Jim Reid, Denis Turcotte and Walter Weathers are directors of our general partner. Messrs. Laurie and Turcotte are Managing Partners in Brookfield's Private Equity Group, Mr. Reid is a Managing Partner and Chief Investment Officer in Brookfield's Private Equity Group. Mr. Weathers is a Senior Vice President for Brookfield Asset Management.

Bill Utt is the Chairman of our general partner. He also is the Chairman of Teekay Corporation. Kenneth Hvid is a director of our general partner. Mr. Hvid is also the President and Chief Executive Officer of Teekay Corporation, and a director of Teekay Tankers Ltd., a publicly-traded subsidiary of Teekay Corporation.

Transactions Relating to the Brookfield Transaction

In September 2017, we completed the Brookfield Transaction, which included the following transactions, among others:

a.Investment and Related Transactions

Brookfield and Teekay Corporation invested $610.0 million and $30.0 million, respectively, in us in exchange for 244.0 million and 12.0 million common units, respectively, at a price of $2.50 per common unit, and 62.4 million (or the Brookfield Purchased Warrants) and 3.1 million common unit warrants, respectively, with an exercise price of $0.01 per unit and which warrants are exercisable at any time until September 25, 2024 if our common unit volume-weighted average price is equal to or greater than $4.00 per unit (or the Threshold Price) for 10 consecutive trading days prior to that date.

Brookfield acquired from Teekay Corporation a 49.0% interest in our general partner in exchange for $4.0 million and an option (or the Option), which it exercised in July 2018, to purchase an additional 2.0% interest in our general partner from Teekay Corporation in exchange for 1.0 million of the Brookfield Purchased Warrants.

Brookfield acquired, from a subsidiary of Teekay Corporation, the $200 million promissory note originally issued by us to such subsidiary in July 2016 and which promissory note was amended and restated (the Brookfield Promissory Note) in connection with the acquisition by Brookfield to, among other things, extend its maturity date from 2019 to 2022. Brookfield purchased the promissory note from Teekay Corporation for $140.0 million in cash and 11.4 million of the Brookfield Purchased Warrants. As described below, in July 2018 Brookfield exchanged the Brookfield Promissory Note for certain of our 8.5% senior unsecured bonds due 2023.

We repurchased and canceled all of our outstanding Series C-1 and Series D preferred units from existing unitholders, for an aggregate of approximately $250.0 million in cash, and at a price per Series C-1 Preferred Unit of $18.20 and per Series D Preferred Unit of $23.75 per unit, plus, in each case, any accrued and unpaid quarterly distributions. As part of such repurchases, we paid to Teekay Corporation an aggregate amount of $24.7 million as a holder of repurchased Series D Preferred Units. Concurrently, the per unit exercise price of our Series D tranche B warrants to purchase common units (which were issued in June 2016 as part of our Series D Preferred Unit financing, and a portion of which warrants are held by Teekay Corporation) was reduced from $6.05 to $4.55.

b.General Partner Agreement

In connection with the Brookfield Transaction, Brookfield and Teekay Corporation entered into an amended and restated limited liability company agreement of our general partner (or the GP LLC Agreement), which governs certain affairs of our general partner and certain rights and obligations among its owners.

Pursuant to the terms of the GP LLC Agreement, Teekay Corporation granted to Brookfield the Option, which it exercised in July 2018.

The GP LLC Agreement provides that, after exercise of the Option, (i) (a) so long as Teekay Corporation owns at least 10% of our outstanding common units, Teekay Corporation has the right to elect two directors to the board of directors and (b) so long as the License Agreement (as defined below) remains in effect, Teekay Corporation has the right to elect one director to the board of directors, and (ii) so long as Brookfield TOGP owns at least 10% of our outstanding common units, Brookfield TOGP has the right to elect two directors to the board of directors. After exercise of the Option, any additional members of the board of directors are elected by the majority owner or owners of our general partner.

The GP LLC Agreement further provides that, until the directors elected by Brookfield TOGP constitute a majority of the board of directors, our general partner and we will not engage in certain actions without Brookfield TOGP’s consent, which actions include, among others and in each case subject to specified exceptions, (i) authorizing, issuing, splitting, combining or reclassifying equity securities of our general partner or us, (ii) incurring indebtedness in excess of $50 million, (iii) amending the organizational documents or specified corporate policies of our general partner or us, (iv) entering into a transaction with any affiliate of ours in excess of $1 million, (v) entering into acquisition or divestment transactions, or making capital expenditures, in each case, in excess of $50 million, (vi) entering into, amending, waiving or terminating contracts in excess of $50 million or certain other contracts, (vii) commencing or settling litigation or dispute resolution proceedings in excess of $5 million, (viii) entering into any merger, business combination or spin-off transaction or taking any other action that requires the approval of the holders of our common units, (ix) increasing or decreasing the size of our general partner’s board of directors, (xi) making material changes to the employment of certain officers, (x) effecting any material change in the nature of our business or operations, (xi) approving a business plan or annual budget of ours involving an increase in expenditures in excess of 5% over the prior fiscal year, (xii) declaring or paying dividends or distributions on equity securities of our general partner or us, excluding ordinary quarterly distributions declared and paid by us of no more than $0.01 per common unit, or (xiii) redeeming, purchasing or otherwise acquiring equity securities of our general partner or us.

So long as Teekay Corporation owns at least 15% of our outstanding common units on a fully diluted basis, (i) Teekay Corporation will have the right to repurchase the general partner interests held by Brookfield TOGP in the event that Brookfield TOGP no longer owns at least 15% of our outstanding common units on a fully-diluted basis, and (ii) Teekay Corporation will have a right of first offer to purchase any general partner interests proposed to be sold by Brookfield TOGP.

In the event (i) that Teekay Corporation owns less than 10% of our outstanding common units and Brookfield TOGP owns at least 15% of our outstanding common units, each on a fully diluted basis, or (ii) of the occurrence of certain events of default, Brookfield TOGP will have the right to purchase the remaining general partner interests held by Teekay Corporation.

For so long as Teekay Corporation owns interests in our general partner, if Brookfield agrees to sell all or substantially all of our common units and the general partner interests it owns, Brookfield TOGP may require Teekay Corporation to participate in the sale on the same terms and conditions as Brookfield TOGP. Brookfield TOGP and Teekay Corporation have also agreed that the preemptive rights granted to our general partner under our partnership agreement will be allocated between Brookfield TOGP and Teekay Corporation, and each of their respective affiliates, based on the relative percentages of our common units and the warrants (on an as-converted basis) owned by them.

c.Trademark License Agreement

We and Teekay Corporation entered into a trademark license agreement (or the License Agreement), pursuant to which Teekay Corporation granted to us a license to use certain intellectual property, including trademarks and service marks owned by Teekay Corporation and its subsidiaries, for no fee in connection with our business, subject to our compliance with Teekay Corporation's quality control standards, applicable legal requirements and other conditions, including operation of our business consistent with certain key performance indicators applicable to Teekay Corporation public company subsidiaries. The License Agreement also contains covenants regarding the protection of Teekay Corporation's intellectual property rights, indemnification obligations of us with respect to our use of the licensed marks, termination, and other customary provisions.

d.Services Agreements

Until December 31, 2017, Teekay Corporation and its wholly-owned subsidiaries directly and indirectly provided, pursuant to various services agreement, a majority of our administrative services needs and a majority of our operating subsidiaries' commercial, technical, crew training, strategic, business development and administrative service needs. In connection with the Brookfield Transaction, Teekay Corporation agreed to transfer to us the Teekay Corporation subsidiaries that are devoted exclusively or nearly exclusively to providing services to us and our subsidiaries pursuant to the services agreements. On January 1, 2018, we acquired a 100% ownership interest in seven subsidiaries of Teekay Corporation for cash consideration of $1.4 million, which subsidiaries provide ship management, commercial, technical, strategic, business development and administrative services, primarily related to our operating subsidiaries' FPSO units, shuttle tankers and FSO units. Teekay Corporation continues to provide to us certain administrative and other services, and since January 1, 2018, we provide to Teekay Corporation certain services, including those relating to its FPSO units.

Because prior to January 1, 2018, certain people providing services to us and our subsidiaries previously were employees of various subsidiaries of Teekay Corporation, their compensation (other than any awards under our long-term incentive plan) prior to January 1, 2018 was set and paid by the Teekay Corporation subsidiary that employed them. These persons included Ingvild Sæther, the President and CEO of Teekay Offshore Group Ltd. and other executives of that entity. Pursuant to our services agreements with Teekay Corporation and its subsidiaries, we agreed to reimburse Teekay Corporation for time spent by such persons on providing services to us and our subsidiaries. These reimbursements are in addition to other fees paid under the various services agreements with Teekay Corporation. Please read Item 18. - Financial Statements: Note 11 - Related Party Transactions and Balances for further information.

e.Registration Rights Agreement

In connection with the Brookfield Transaction, we, Brookfield TOLP and Teekay Corporation entered into a registration rights agreement relating to the registration under the U.S. Securities Act of 1933, as amended, of certain common units and warrants. During the period the registration rights agreement is in effect, Brookfield and Teekay Corporation will suspend our general partner's existing registration rights under our partnership agreement. The registration rights agreement provides each of Brookfield TOLP and Teekay Corporation with the right to include our common units held by them as of the closing of the Brookfield Transaction (including common units issuable upon the exercise of warrants issued to them in the Brookfield Transaction). In any registration statement filed by us in connection with a public offering of our common units or securities convertible into, or exchangeable for, common units, subject to customary exceptions and limitations. The registration rights agreement provides that registration expenses, including the reasonable fees and expenses of any counsel on behalf of the holders of the securities to be registered, will be borne by us.

f.Loan from Brookfield and Teekay Corporation

Please read Item 18. - Financial Statements: Note 11(h) - Related Party Transactions and Balances for a description of a $125 million revolving credit agreement we entered into with Brookfield and Teekay Corporation in March 2018.

g.2018 Purchase of Senior Unsecured Bonds by Brookfield

Please read Item 18. - Financial Statements: Note 11(i) - Related Party Transactions and Balances for a description of Brookfield's purchase from us in July 2018 of $500 million principal amount of our 8.50% senior unsecured bonds due 2023, and related transactions.

Omnibus Agreement

In connection with our initial public offering in 2006, we entered into an omnibus agreement with our general partner, Teekay Corporation, Teekay LNG and related parties. The following discussion describes certain provisions of the omnibus agreement, as it has been amended.

Noncompetition. Under the omnibus agreement, Teekay Corporation and Teekay LNG have agreed, and have caused their controlled affiliates (other than us) to agree, not to own, operate or charter certain "Offshore Assets" (including shuttle tankers, FSO units and FPSO units). This restriction does not prevent Teekay Corporation, Teekay LNG or any of their other controlled affiliates from, among other things:

- owning, operating or chartering Offshore Assets if the remaining duration of the time charter or contract of affreightment for the vessel, excluding any extension options, is less than three years; or

• acquiring, operating or chartering Offshore Assets if our general partner has previously advised Teekay Corporation or Teekay LNG that the board of directors of our general partner has elected, with the approval of its Conflicts Committee, not to cause us or our subsidiaries to acquire or operate the vessels.

In addition, under the omnibus agreement we have agreed not to own, operate or charter crude oil tankers or liquefied natural gas (or LNG) carriers. This restriction does not apply to any of the Aframax tankers in our current fleet, and the ownership, operation or chartering of any oil tankers that replace any of those oil tankers in connection with certain events. In addition, the restriction does not prevent us from, among other things, acquiring, operating or chartering oil tankers or LNG carriers if Teekay Corporation or Teekay LNG, respectively, has previously advised our general partner that it has elected not to acquire or operate those vessels.

Rights of First Offer on Conventional Tankers, LNG Carriers and Offshore Vessels. Under the omnibus agreement, we have granted to Teekay Corporation and Teekay LNG a 30-day right of first offer on certain (a) sales, transfers or other dispositions of any Aframax tankers, in the case of Teekay Corporation, or certain LNG carriers in the case of Teekay LNG, or (b) re-charterings of any Aframax tankers or LNG carriers pursuant to a time charter or contract of affreightment with a term of at least three years if the existing charter expires or is terminated early. Likewise, each of Teekay Corporation and Teekay LNG has granted a similar right of first offer to us for any Offshore Vessels it might own that, at the time of the proposed offer, is subject to a time charter or contract of affreightment with a remaining term, excluding extension options, of at least three years. These rights of first offer do not apply to certain transactions.

The omnibus agreement and a subsequent agreement also obligated Teekay Corporation to offer to sell to us the Foinaven FPSO unit, an existing unit of a wholly-owned subsidiary of Teekay Corporation, subject to approvals required from the charterer. The purchase price for the Foinaven FPSO unit would be its fair market value.

Termination. If Teekay Corporation or its affiliates no longer control our general partner or the general partner of Teekay LNG Partners L.P. or if there is a change of control of Teekay Corporation, our general partner, the general partner of Teekay LNG Partners L.P. or Teekay Corporation, as applicable, may terminate relevant non-competition and rights of first offer provisions of the omnibus agreement.

Other

Please read Item 18. - Financial Statements: Note 11 - Related Party Transactions and Balances for additional information about these and various other related-party transactions.

Item 8. Financial Information

Consolidated Financial Statements and Other Financial Information

Consolidated Financial Statements and Notes

Please see Item 18 below for additional information required to be disclosed under this Item.

Legal Proceedings

Occasionally we have been, and expect to continue to be, subject to legal proceedings and claims in the ordinary course of our business, principally personal injury and property casualty claims. These claims, even if lacking merit, could result in the expenditure of significant financial and managerial resources.

Please read Item 18. – Financial Statements: Note 14 – Commitments and Contingencies for a description of certain claims made against us. Please read Item 5. Operating and Financial Review and Prospects - Management’s Discussion and Analysis of Financial Condition and Results of Operations - Significant Developments -- Settlement Agreements with Petrobras for a description of the resolution of certain claims involving us.

Cash Distribution Policy

Rationale for Our Cash Distribution Policy

Our cash distribution policy, which is consistent with our partnership agreement, requires us to distribute all of our available cash (as defined in our partnership agreement and after deducting expenses, including estimated maintenance capital expenditures and reserves) rather than our retaining it each quarter. Available cash is determined after payment of distributions on our preferred units. In determining the amount of cash available for distribution, the board of directors of our general partner, in making the determination on our behalf, approves the amount of cash reserves to set aside, including reserves for future capital expenditures, anticipated future credit needs, working capital and other matters. We also rely upon external financing sources, including commercial borrowings and proceeds from debt and equity offerings, to fund our capital expenditures. Accordingly, to the extent we do not have sufficient cash reserves or are unable to obtain financing, our cash distribution policy may significantly impair our ability to meet our financial needs or to grow.

Although global crude oil and gas prices have experienced moderate recovery since falling from the highs of mid-2014, prices have not returned to those same highs and remain volatile due to global and regional geopolitical, economic and strategic risks and changes. Other factors beyond our control have adversely affected energy and master limited partnership capital markets and available sources of financing. Based on capital requirements for our committed growth projects and scheduled debt repayment obligations, coupled with uncertainty regarding how long it will take for the energy and master limited partnership capital markets to normalize, we believe it is in the best interests of our common unitholders to conserve more of our internally-generated cash flows to fund these projects and to reduce debt levels. As a result, in January 2019, we reduced our quarterly distributions on our common units to $nil, and our near-to-medium-term business strategy is primarily focused on funding and implementing existing growth projects, extending contracts and redeploying existing assets on long-term charters and repaying or refinancing scheduled debt obligations.

Limitations on Cash Distributions; Our Ability to Change Our Cash Distribution Policy

There is no guarantee that unitholders will receive quarterly distributions from us. Our distribution policy is subject to certain restrictions and may be changed at any time, including:

- Our unitholders have no contractual or other legal right to receive distributions other than the obligation under our partnership agreement to distribute available cash on a quarterly basis, which is subject to our general partner's broad discretion to establish reserves and other limitations.
- While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended with the approval of a majority of the outstanding common units.
- Even if our cash distribution policy is not modified or revoked, the amount of distributions, if any, we pay under our cash distribution policy and the decision to make any distribution is determined by the board of directors of our general partner, taking into consideration the terms of our partnership agreement.
- Under Section 51 of the Marshall Islands Limited Partnership Act, we may not make a distribution to unitholders to the extent that at the time of the distribution, after giving effect to the distribution, all of our liabilities, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specified property of ours, exceed the fair value of our assets, except that the fair value of property that is subject to a liability for which the recourse of creditors is limited shall be included in our assets only to the extent that the fair value of that property exceeds that liability.
- We may lack sufficient cash to pay distributions to our unitholders due to decreases in net revenues or increases in operating expenses, principal and interest payments on outstanding debt, tax expenses, working capital requirements, maintenance capital expenditures or anticipated cash needs.
- Our distribution policy may be affected by restrictions on distributions under our credit facility agreements, which contain material financial tests and covenants that must be satisfied. Should we be unable to satisfy these restrictions included in the credit agreements or if we are otherwise in default under the credit agreements, we would be prohibited from making cash distributions, which would materially hinder our ability to make cash distributions to unitholders, notwithstanding our stated cash distribution policy.
- If we make distributions out of capital surplus, as opposed to operating surplus (as such terms are defined in our partnership agreement), those distributions will constitute a return of capital and will result in a reduction in the minimum quarterly distribution and the target distribution levels under our partnership agreement. We do not anticipate that we will make any distributions from capital surplus.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash from our operating surplus (as defined in our partnership agreement) after the minimum quarterly distribution to our common unitholders and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, without unitholder approval. Any transfer by our general partner of the incentive distribution rights would not change the percentage allocations of quarterly distributions with respect to such rights.

Our general partner is entitled to incentive distributions if the amount we distribute to common unitholders with respect to any quarter exceeds specified target levels shown below. The amounts set forth under "Marginal Percentage Interest" are the percentage interests of the common unitholders and our general partner in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Target Amount (per unit)", until available cash from operating surplus we distribute reaches the next target distribution level, if any. The percentage interests shown for the common unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests shown for our general partner include its 0.76% general partner interest as at December 31, 2018 and assumes the general partner has contributed any capital necessary to maintain its 0.76% general partner interest and has not transferred the incentive distribution rights.

	Marginal Percentage Interest in Distributions			
Quarterly Distribution Target Amount (per unit)	Unitholders		General Partner	
Minimum quarterly distribution of $0.35	99.24	%	0.76	%
Up to $0.4025	99.24	%	0.76	%
Above $0.4025 up to $0.4375	86.24	%	13.76	%
Above $0.4375 up to $0.525	76.24	%	23.76	%
Above $0.525	51.24	%	48.76	%

During 2018, cash distributions were below $0.35 per common unit. Consequently, the increasing percentages were not used to calculate the general partner's interest in net (loss) income for the purposes of the net (loss) income per common unit calculation for the year ended December 31, 2018.

In the event of a liquidation, all property and cash in excess of that required to discharge all liabilities and liquidation amounts on the Series A, Series B and Series E preferred units will be distributed to the common unitholders and the general partner in proportion to their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation in accordance with the partnership agreement.

Significant Changes

Not applicable.

Item 9. The Offer and Listing

Our common units are traded on the NYSE under the symbol "TOO". Our Series A Preferred Units are traded on the NYSE under the symbol "TOO-PRA". Our Series B Preferred Units are traded on the NYSE under the symbol "TOO-PRB". Our Series E Preferred Units are traded on the NYSE under the symbol "TOO-PRE". Our 6.00% Notes due 2019 are traded on the NYSE under the trading number "EK289435".

Item 10. Additional Information

Memorandum and Articles of Association

The information required to be disclosed under Item 10B is incorporated by reference to our Registration Statement on Form 8-A/A filed with the SEC on March 20, 2018.

Material Contracts

The following is a summary of each material contract, other than material contracts entered into in the ordinary course of business, to which we or any of our subsidiaries is a party, for the two years immediately preceding the date of this Annual Report, each of which is included in the list of exhibits in Item 19:

a) Amended and Restated Omnibus Agreement, dated December 19, 2006, among us, our general partner, Teekay Corporation, Teekay LNG and related parties. Please read Item 7 – Major Unitholders and Related Party Transactions – Certain Relationships and Related Party Transactions for a summary of certain contract terms.

b) We and certain of our operating subsidiaries have entered into services agreements with certain subsidiaries of Teekay Corporation pursuant to which the Teekay Corporation subsidiaries provide certain administrative services to the Partnership and certain administrative, advisory, technical, strategic consulting services, business development and ship management services to operating subsidiaries for a reasonable fee that includes reimbursement of their direct and indirect expenses incurred in providing these services. Please read Item 7 – Major Unitholders and Related Party Transactions – Certain Relationships and Related Party Transactions for a summary of certain contract terms.

c) Teekay Offshore Partners L.P. 2006 Long-Term Incentive Plan. Please read Item 6 – Directors, Senior Management and Employees – 2006 Long-term Incentive Plan for a summary of certain plan terms.

d) Agreement, dated September 8, 2017, for U.S. $600,000,000 Revolving Credit Facility, between Teekay Shuttle Tankers L.L.C. and Den Norske Bank Capital L.L.C. and various other banks.

e) Indenture, dated as of July 2, 2018, for U.S. $700,000,000 aggregate principal amount of 8.50% Senior Notes due 2023, between Teekay Offshore Partners L.P., Teekay Offshore Finance Corp. and The Bank of New York Mellon, as trustee.

f) Second Supplemental Indenture, dated as of July 3, 2018, among Teekay Offshore Partners, L.P., Teekay Offshore Finance Corp. and The Bank of New York Mellon, as trustee.

g) Investment Agreement, dated as of July 26, 2017, by and between Teekay Offshore Partners L.P. and Brookfield TK TOLP L.P.

h)

Investment Agreement, dated as of July 26, 2017, between Teekay Offshore Partners L.P. and Teekay Holdings Limited.

i) Purchase Agreement, dated as of July 26, 2017, between Teekay Holdings Limited and Brookfield TK TOGP L.P.

j) Amended and Restated Subordinate Promissory Note, dated as of July 26, 2017, by and between Teekay Offshore Partners L.P., Teekay Corporation and Brookfield TK TOLP L.P.

k) Warrant Agreement, dated as of September 25, 2017, by and between Teekay Offshore Partners L.P. and Brookfield TK TOLP L.P.

l) Warrant Agreement, dated as of September 25, 2017, by and between Teekay Offshore Partners L.P. and Teekay Shipping Limited .

m) Registration Rights Agreement, dated September 25, 2017, by and between Teekay Offshore Partners L.P., Teekay Corporation and Brookfield TK TOLP L.P.

Exchange Controls and Other Limitations Affecting Unitholders

We are not aware of any governmental laws, decrees or regulations, including foreign exchange controls, in the Republic of the Marshall Islands that restrict the export or import of capital, or that affect the remittance of distributions, interest or other payments to holders of our securities that are non-resident and not citizens and otherwise not conducting business or transactions in the Republic of the Marshall Islands.

We are not aware of any limitations on the right of non-resident or foreign owners to hold or vote our securities imposed by the laws of the Republic of the Marshall Islands or our partnership agreement.

Material U.S. Federal Income Tax Considerations

The following is a discussion of certain material U.S. federal income tax considerations that may be relevant to unitholders. This discussion is based upon the provisions of the Internal Revenue Code of 1986, as amended (or the Code), legislative history, applicable U.S. Treasury Regulations (or Treasury Regulations), judicial authority and administrative interpretations, all as in effect on the date of this Annual Report, and which are subject to change, possibly with retroactive effect, or are subject to different interpretations. Changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to “we,” “our” or “us” are references to Teekay Offshore Partners L.P.

This discussion is limited to unitholders who hold their units as capital assets for tax purposes. This discussion does not address all tax considerations that may be important to a particular unitholder in light of the unitholder’s circumstances, or to certain categories of unitholders that may be subject to special tax rules, such as:

- dealers in securities or currencies,
- traders in securities that have elected the mark-to-market method of accounting for their securities,
- persons whose functional currency is not the U.S. dollar,
- persons holding our units as part of a hedge, straddle, conversion or other “synthetic security” or integrated transaction,
- certain U.S. expatriates,
- financial institutions,
- insurance companies,
- persons subject to the alternative minimum tax,
- persons that actually or under applicable constructive ownership rules own 10% or more of our units (by vote or value), and
- entities that are tax-exempt for U.S. federal income tax purposes.

If a partnership (including any entity or arrangement treated as a partnership for U.S. federal income tax purposes) holds our units, the tax treatment of a partner generally will depend upon the status of the partner and the activities of the partnership. Partners in partnerships holding our units should consult their tax advisors to determine the appropriate tax treatment of the partnership’s ownership of our units.

This discussion does not address any U.S. estate tax considerations or tax considerations arising under the laws of any state, local or non-U.S. jurisdiction. Each unitholder is urged to consult its tax advisor regarding the U.S. federal, state, local, non-U.S. and other tax consequences of the ownership or disposition of our units.

United States Federal Income Taxation of U.S. Holders

As used herein, the term U.S. Holder means a beneficial owner of our units that is for U.S. federal income tax purposes: (i) a U.S. citizen or U.S. resident alien (or a U.S. Individual Holder), (ii) a corporation or other entity taxable as a corporation, that was created or organized under the laws of the United States, any state thereof or the District of Columbia, (iii) an estate whose income is subject to U.S. federal income taxation regardless of its source, or (iv) a trust that either is subject to the supervision of a court within the United States and has one or more U.S. persons with authority to control all of its substantial decisions or has a valid election in effect under applicable Treasury Regulations to be treated as a U.S. person.

Distributions

We have elected to be taxed as a corporation for U.S. federal income tax purposes. Subject to the discussion of passive foreign investment companies (or PFICs) below, any distributions made by us to a U.S. Holder generally will constitute dividends, which may be taxable as ordinary income or "qualified dividend income" as described in more detail below, to the extent of our current and accumulated earnings and profits allocated to the U.S. Holder's units, as determined under U.S. federal income tax principles. Distributions in excess of our current and accumulated earnings and profits allocated to the U.S. Holder's units will be treated first as a nontaxable return of capital to the extent of the U.S. Holder's tax basis in our units and thereafter as capital gain, which will be either long term or short term capital gain depending upon whether the U.S. Holder has held the units for more than one year. U.S. Holders that are corporations for U.S. federal income tax purposes generally will not be entitled to claim a dividends received deduction with respect to any distributions they receive from us. For purposes of computing allowable foreign tax credits for U.S. federal income tax purposes, dividends received with respect to our units will be treated as foreign source income and generally will be treated as “passive category income.”

Subject to holding period requirements and certain other limitations, dividends received with respect to our publicly-traded units by a U.S. Holder who is an individual, trust or estate (or a Non-Corporate U.S. Holder) will be treated as “qualified dividend income” that is taxable to such Non-Corporate U.S. Holder at preferential capital gain tax rates provided that we are not classified as a PFIC for the taxable year during which the dividend is paid or the immediately preceding taxable year (we intend to take the position that we are not now and have never been classified as a PFIC, as discussed below). Any dividends received with respect to our units not eligible for these preferential rates will be taxed as ordinary income to a Non-Corporate U.S. Holder.

Special rules may apply to any “extraordinary dividend” paid by us. Generally, an extraordinary dividend is a dividend with respect to a share of stock if the amount of the dividend is equal to or in excess of 10% of a common stockholder’s, or 5% of a preferred stockholder’s adjusted tax basis (or fair market value in certain circumstances) in such stock. In addition, extraordinary dividends include dividends received within a one year period that, in the aggregate, equal or exceed 20% of a stockholder’s adjusted tax basis (or fair market value in certain circumstances). If we pay an “extraordinary dividend” on our units that is treated as “qualified dividend income,” then any loss recognized by a Non-Corporate U.S. Holder from the sale or exchange of such units will be treated as long-term capital loss to the extent of the amount of such dividend.

Certain Non-Corporate U.S. Holders are subject to a 3.8% tax on certain investment income, including dividends. Non-Corporate U.S. Holders should consult their tax advisors regarding the effect, if any, of this tax on their ownership of our units.

Sale, Exchange or Other Disposition of Units

Subject to the discussion of PFICs below, a U.S. Holder generally will recognize capital gain or loss upon a sale, exchange or other disposition of our units in an amount equal to the difference between the amount realized by the U.S. Holder from such sale, exchange or other disposition and the U.S. Holder’s tax basis in such units. Subject to the discussion of extraordinary dividends above, such gain or loss generally will be treated as (a) long-term capital gain or loss if the U.S. Holder’s holding period is greater than one year at the time of the sale, exchange or other disposition, or short-term capital gain or loss otherwise and (b) U.S.-source gain or loss, as applicable, for foreign tax credit purposes. Non-Corporate U.S. Holders may be eligible for preferential rates of U.S. federal income tax in respect of long-term capital gains. A U.S. Holder’s ability to deduct capital losses is subject to certain limitations.

Certain Non-Corporate U.S. Holders are subject to a 3.8% tax on certain investment income, including capital gains from the sale or other disposition of units. Non-Corporate U.S. Holders should consult their tax advisors regarding the effect, if any, of this tax on their disposition of our units.

Consequences of Possible PFIC Classification

A non-U.S. entity treated as a corporation for U.S. federal income tax purposes will be treated as a PFIC in any taxable year in which, after taking into account the income and assets of the corporation and certain subsidiaries pursuant to a “look through” rule, either: (i) at least 75% of its gross income is “passive” income, or (ii) at least 50% of the average value of its assets is attributable to assets that produce, or are held for the production of, passive income.

For purposes of these tests, “passive income” includes dividends, interest, gains from the sale or exchange of investment property and rents and royalties other than rents and royalties that are received from unrelated parties in connection with the active conduct of a trade or business. By contrast, income derived from the performance of services does not constitute “passive income.”

There are legal uncertainties involved in determining whether the income derived from our time-chartering activities constitutes rental income or income derived from the performance of services, including legal uncertainties arising from the decision in Tidewater Inc. v. United States, 565 F.3d 299 (5th Cir. 2009), which held that income derived from certain time-chartering activities should be treated as rental income rather than services income for purposes of a foreign sales corporation provision of the Code. However, the Internal Revenue Service (or IRS) stated in an Action on Decision (AOD 2010-01) that it disagrees with, and will not acquiesce to, the way that the rental versus services framework was applied to the facts in the Tidewater decision, and in its discussion stated that the time charters at issue in Tidewater would be treated as producing services income for PFIC purposes. The IRS's statement with respect to Tidewater cannot be relied upon or otherwise cited as precedent by taxpayers. Consequently, in the absence of any binding legal authority specifically relating to the statutory provisions governing PFICs, there can be no assurance that the IRS or a court would not follow the Tidewater decision in interpreting the PFIC provisions of the Code. Moreover, the market value of our units may be treated as reflecting the value of our assets at any given time. Therefore, a decline in the market value of our units, which is not within our control, may impact the determination of whether we are a PFIC. Nevertheless, based on our and our subsidiaries' current assets and operations, we intend to take the position that we are not now and have never been a PFIC. No assurance can be given, however, that the IRS, or a court of law, will accept our position or that we would not constitute a PFIC for any future taxable year if there were to be changes in our or our subsidiaries' assets, income or operations.

As discussed more fully below, if we were to be treated as a PFIC for any taxable year, a U.S. Holder generally would be subject to different taxation rules depending on whether the U.S. Holder makes a timely and effective election to treat us as a "Qualified Electing Fund" (a QEF election). As an alternative to making a QEF election, a U.S. Holder should be able to make a "mark-to-market" election with respect to our units, as discussed below.

Taxation of U.S. Holders Making a Timely QEF Election. A U.S. Holder who makes a timely QEF election (an Electing Holder), must report the Electing Holder's pro rata share of our ordinary earnings and net capital gain, if any, for each taxable year for which we are a PFIC that ends with or within the Electing Holder's taxable year, regardless of whether or not the Electing Holder received distributions from us in that year. Such income inclusions would not be eligible for the preferential tax rates applicable to qualified dividend income. The Electing Holder's adjusted tax basis in our units will be increased to reflect taxed but undistributed earnings and profits. Distributions of earnings and profits that were previously taxed will result in a corresponding reduction in the Electing Holder's adjusted tax basis in our units and will not be taxed again once distributed. An Electing Holder generally will recognize capital gain or loss on the sale, exchange or other disposition of our units. A U.S. Holder makes a QEF election with respect to any year that we are a PFIC by filing IRS Form 8621 with the U.S. Holder's timely filed U.S. federal income tax return (including extensions).

If a U.S. Holder has not made a timely QEF election with respect to the first year in the U.S. Holder's holding period of our units during which we qualified as a PFIC, the U.S. Holder may be treated as having made a timely QEF election by filing a QEF election with the U.S. Holder's timely filed U.S. federal income tax return (including extensions) and, under the rules of Section 1291 of the Code, a "deemed sale election" to include in income as an "excess distribution" (described below) the amount of any gain that the U.S. Holder would otherwise recognize if the U.S. Holder sold the U.S. Holder's units on the "qualification date". The qualification date is the first day of our taxable year in which we qualified as a "qualified electing fund" with respect to such U.S. Holder. In addition to the above rules, under very limited circumstances, a U.S. Holder may make a retroactive QEF election if the U.S. Holder failed to file the QEF election documents in a timely manner. If a U.S. Holder makes a timely QEF election for one of our taxable years, but did not make such election with respect to the first year in the U.S. Holder's holding period of our units during which we qualified as a PFIC and the U.S. Holder did not make the deemed sale election described above, the U.S. Holder also will be subject to the more adverse rules described below.

A U.S. Holder's QEF election will not be effective unless we annually provide the U.S. Holder with certain information concerning our income and gain, calculated in accordance with the Code, to be included with the U.S. Holder's U.S. federal income tax return. We have not provided our U.S. Holders with such information in prior taxable years and do not intend to provide such information in the current taxable year. Accordingly, U.S. Holders will not be able to make an effective QEF election at this time. If, contrary to our expectations, we determine that we are or will be a PFIC for any taxable year, we will provide U.S. Holders with the information necessary to make an effective QEF election with respect to our units.

Taxation of U.S. Holders Making a "Mark-to-Market" Election. If we were to be treated as a PFIC for any taxable year and, as we anticipate, our units were treated as "marketable stock," then, as an alternative to making a QEF election, a U.S. Holder would be allowed to make a "mark-to-market" election with respect to our units, provided the U.S. Holder completes and files IRS Form 8621 in accordance with the relevant instructions and related Treasury Regulations. If that election is made for the first year a U.S. Holder holds or is deemed to hold our units and for which we are a PFIC, the U.S. Holder generally would include as ordinary income in each taxable year that we are a PFIC the excess, if any, of the fair market value of the U.S. Holder's units at the end of the taxable year over the U.S. Holder's adjusted tax basis in the units. The U.S. Holder also would be permitted an ordinary loss in respect of the excess, if any, of the U.S. Holder's adjusted tax basis in the units over the fair market value thereof at the end of the taxable year that we are a PFIC, but only to the extent of the net amount previously included in income as a result of the mark-to-market election. A U.S. Holder's tax basis in our units would be adjusted to reflect any such income or loss recognized. Gain recognized on the sale, exchange or other disposition of our units in taxable years that we are a PFIC would be treated as ordinary income, and any loss recognized on the sale, exchange or other disposition of the units in taxable years that we are a PFIC would be treated as ordinary loss to the extent that such loss does not exceed the net mark-to-market gains previously included in income by the U.S. Holder. Because the mark-to-market election only applies to marketable stock, however, it would not apply to a U.S. Holder's indirect interest in any of our subsidiaries that were also determined to be PFICs.

If a U.S. Holder makes a mark-to-market election for one of our taxable years and we were a PFIC for a prior taxable year during which such U.S. Holder held our units and for which (i) we were not a QEF with respect to such U.S. Holder and (ii) such U.S. Holder did not make a timely mark-to-market election, such U.S. Holder would also be subject to the more adverse rules described below in the first taxable year for which the mark-to-market election is in effect and also to the extent the fair market value of the U.S. Holder's units exceeds the U.S. Holder's adjusted tax basis in the units at the end of the first taxable year for which the mark-to-market election is in effect.

Taxation of U.S. Holders Not Making a Timely QEF or Mark-to-Market Election. If we were to be treated as a PFIC for any taxable year, a U.S. Holder who does not make either a QEF election or a "mark-to-market" election for that year (a Non-Electing Holder) would be subject to special rules resulting in increased tax liability with respect to (i) any excess distribution (i.e., the portion of any distribution received by the Non-Electing Holder on our units in a taxable year in excess of 125% of the average annual distributions received by the Non-Electing Holder in the three preceding taxable years or, if shorter, the Non-Electing Holder's holding period for our units), and (ii) any gain realized on the sale, exchange or other disposition of our units. Under these special rules:

- the excess distribution or gain would be allocated ratably over the Non-Electing Holder's aggregate holding period for our units;
- the amount allocated to the current taxable year and any taxable year prior to the taxable year we were first treated as a PFIC with respect to the Non-Electing Holder would be taxed as ordinary income in the current taxable year;
- the amount allocated to each of the other taxable years would be subject to U.S. federal income tax at the highest rate of tax in effect for the applicable class of taxpayer for that year; and
- an interest charge for the deemed deferral benefit would be imposed with respect to the resulting tax attributable to each such other taxable year.

Additionally, for each year during which a U.S. Holder holds units, we are a PFIC, and the total value of all PFIC units that such U.S. Holder directly or indirectly holds exceeds certain thresholds, such U.S. Holder will be required to file IRS Form 8621 with its annual U.S. federal income tax return to report its ownership of our units. In addition, if a Non-Electing Holder who is an individual dies while owning our units, such Non-Electing Holder's successor generally would not receive a step-up in tax basis with respect to such units.

U.S. Holders are urged to consult their tax advisors regarding the PFIC rules, including the PFIC annual reporting requirements as well as the applicability, availability and advisability of, and procedure for, making QEF, Mark-to-Market and other available elections with respect to us, and the U.S. federal income tax consequences of making such elections.

U.S. Return Disclosure Requirements for U.S. Individual Holders

U.S. Individual Holders who hold certain specified foreign financial assets, including stock in a foreign corporation that is not held in an account maintained by a financial institution, with an aggregate value in excess of $50,000, on the last day of a taxable year, or $75,000 at any time during that taxable year, may be required to report such assets on IRS Form 8938 with their U.S. federal income tax return for that taxable year. This reporting requirement does not apply to U.S. Individual Holders who report their ownership of our units under the PFIC annual reporting rules described above. Penalties apply for failure to properly complete and file IRS Form 8938. U.S. Individual Holders are encouraged to consult with their tax advisors regarding the possible application of this disclosure requirement to their investment in our units.

United States Federal Income Taxation of Non-U.S. Holders

A beneficial owner of our units (other than a partnership, including any entity or arrangement treated as a partnership for U.S. federal income tax purposes) that is not a U.S. Holder is a Non-U.S. Holder.

Distributions

In general, a non-U.S. Holder will not be subject to U.S. federal income tax on distributions received from us with respect to our units unless the distributions are effectively connected with the Non-U.S. Holder's conduct of a trade or business within the United States (and, if required by an applicable income tax treaty, are attributable to a permanent establishment that the Non-U.S. Holder maintains in the United States). If a Non-U.S. Holder is engaged in a trade or business within the United States and the distributions are deemed to be effectively connected to that trade or business, the Non-U.S. Holder generally will be subject to U.S. federal income tax on those distributions in the same manner as if it were a U.S. Holder.

Sale, Exchange or Other Disposition of Units

In general, a non-U.S. Holder is not subject to U.S. federal income tax on any gain resulting from the disposition of our units unless (a) such gain is effectively connected with the Non-U.S. Holder's conduct of a trade or business within the United States (and, if required by an applicable income tax treaty, is attributable to a permanent establishment that the Non-U.S. Holder maintains in the United States) or (b) the Non-U.S. Holder is an individual who is present in the United States for 183 days or more during the taxable year in which such disposition occurs and meets certain other requirements. If a Non-U.S. Holder is engaged in a trade or business within the United States and the disposition of our units is deemed to be effectively connected to that trade or business, the Non-U.S. Holder generally will be subject to U.S. federal income tax on the resulting gain in the same manner as if it were a U.S. Holder.

Information Reporting and Backup Withholding

In general, payments of distributions with respect to, or the proceeds of a disposition of our units to a Non-Corporate U.S. Holder will be subject to information reporting requirements. These payments to a Non-Corporate U.S. Holder also may be subject to backup withholding if the Non-Corporate U.S. Holder:

- fails to timely provide an accurate taxpayer identification number;
- is notified by the IRS that it has failed to report all interest or distributions required to be shown on its U.S. federal income tax returns; or
- in certain circumstances, fails to comply with applicable certification requirements.

Non-U.S. Holders may be required to establish their exemption from information reporting and backup withholding on payments made to them within the United States, or through a U.S. payor, by certifying their status on IRS Form W-8BEN, W-8BEN-E, W-8ECI or W-8IMY, as applicable.

Backup withholding is not an additional tax. Rather, a unitholder generally may obtain a credit for any amount withheld against its liability for U.S. federal income tax (and obtain a refund of any amounts withheld in excess of such liability) by accurately completing and timely filing a U.S. federal income tax return with the IRS.

Non-United States Tax Considerations

Marshall Islands Tax Considerations. Because we and our subsidiaries do not, and we do not expect that we or they will, conduct business, transactions or operations in the Republic of the Marshall Islands, and because all documentation related to our initial public offering and follow-on offerings was executed outside of the Republic of the Marshall Islands, under current Marshall Islands law, holders of our units will not be subject to Marshall Islands taxation or withholding on distributions, including upon a return of capital, we make to our unitholders, so long as such persons are not citizens of and do not reside in, maintain offices in, nor engage in business, operations, or transactions in the

Republic of the Marshall Islands. In addition, such unitholders will not be subject to Marshall Islands stamp, capital gains or other taxes on the purchase, ownership or disposition of units, and they will not be required by the Republic of the Marshall Islands to file a tax return relating to the units. It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent jurisdictions, including the Marshall Islands, of such unitholder's investment in us. Accordingly, each unitholder is urged to consult its tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and non-U.S., as well as U.S. federal tax returns that may be required of such unitholder.

Canadian Federal Income Tax Considerations. The following discussion is a summary of the material Canadian federal income tax considerations under the Income Tax Act (Canada) (or the Canada Tax Act) that we believe are relevant to holders of units who, for the purposes of the Canada Tax Act and the Canada-United States Tax Convention 1980 (or the Canada-U.S. Treaty), are at all relevant times resident in the United States and entitled to all of the benefits of the Canada-U.S. Treaty and who deal at arm's length with us and Teekay Corporation, Brookfield, Brookfield TOLP and Brookfield TOGP (or U.S. Resident Holders). This discussion takes into account all proposed amendments to the Canada Tax Act and the regulations thereunder that have been publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof and assumes that such proposed amendments will be enacted substantially as proposed. However, no assurance can be given that such proposed amendments will be enacted in the form proposed or at all.

Teekay Offshore Partners L.P. is considered to be a partnership under Canadian federal income tax law and therefore not a taxable entity for Canadian income tax purposes. A U.S. Resident Holder will not be liable to tax under the Canada Tax Act on any income or gains allocated by Teekay Offshore Partners L.P. to the U.S. Resident Holder in respect of such U.S. Resident Holder's units, provided that (a) Teekay Offshore Partners L.P. does not carry on business in Canada for purposes of the Canada Tax Act and (b) such U.S. Resident Holder does not hold such units in connection with a business carried on by such U.S. Resident Holder through a permanent establishment in Canada for purposes of the Canada-U.S. Treaty.

A U.S. Resident Holder will not be liable to tax under the Canada Tax Act on any income or gain from the sale, redemption or other disposition of such U.S. Resident Holder's units, provided that, for purposes of the Canada-U.S. Treaty, such units do not, and did not at any time in the twelve-month period preceding the date of disposition, form part of the business property of a permanent establishment in Canada of such U.S. Resident Holder.

We believe that the activities and affairs of Teekay Offshore Partners L.P. are conducted in such a manner that Teekay Offshore Partners L.P. is not carrying on business in Canada and that U.S. Resident Holders should not be considered to be carrying on business in Canada for purposes of the Canada Tax Act or the Canada-U.S. Treaty solely by reason of the acquisition, holding, disposition or redemption of our units. We intend that this is and continues to be the case, notwithstanding that Teekay Shipping Limited (a subsidiary of Teekay Corporation that is a non-resident of Canada) and Service Provider (an indirect subsidiary of Teekay Offshore Partners L.P. that is a non-resident of Canada) provide certain services to Teekay Offshore Partners L.P. and obtain some or all such services under subcontracts with Canadian service providers. If the arrangements we have entered into result in Teekay Offshore Partners L.P. being considered to carry on business in Canada for purposes of the Canada Tax Act, U.S. Resident Holders would be considered to be carrying on business in Canada and may be required to file Canadian tax returns and, subject to any relief provided under the Canada-U.S. Treaty, would be subject to taxation in Canada on any income that is considered to be attributable to the business carried on by Teekay Offshore Partners L.P. in Canada. The Canada-U.S. Treaty contains a treaty benefit denial rule which may have the effect of denying relief thereunder from Canadian taxation to U.S. Resident Holders in respect of any income attributable to a business carried on by us in Canada.

Although we do not intend to do so, there can be no assurance that the manner in which we carry on our activities will not change from time to time as circumstances dictate or warrant in a manner that may cause U.S. Resident Holders to be carrying on business in Canada for purposes of the Canada Tax Act. Further, the relevant Canadian federal income tax law may change by legislation or judicial interpretation and the Canadian taxing authorities may take a different view than we have of the current law.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent jurisdictions, including Canada, of an investment in us. Accordingly, each unitholder is urged to consult, and depend upon, such unitholder's tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and non-U.S., as well as U.S. federal tax returns, that may be required of such unitholder.

Documents on Display

Documents concerning us that are referred to herein may be accessed on our website under "Investors - Teekay Offshore Partners L.P. - Financials & Presentations" from the home page of our web site at www.teekay.com, or may be inspected at our principal executive offices at 4th Floor, Belvedere Building, 69 Pitts Bay Road, Hamilton, HM 08, Bermuda. Those documents electronically filed via the SEC's Electronic Data Gathering, Analysis, and Retrieval (or EDGAR) system may also be obtained from the SEC's website at www.sec.gov, free of charge.

Item 11. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

We are exposed to the impact of interest rate changes, primarily through our floating-rate borrowings that require us to make interest payments based on LIBOR or NIBOR. Significant increases in interest rates could adversely affect operating margins, results of operations and our ability to service our debt. From time to time, we use interest rate swaps to reduce our exposure to market risk from changes in interest rates. The principal objective of these contracts is to minimize the risks and costs associated with our floating-rate debt.

We are exposed to credit loss in the event of non-performance by the counterparties to the interest rate swap agreements. In order to minimize counterparty risk, to the extent possible and practical, interest rate swaps are entered into with different counterparties to reduce concentration risk.

The tables below provide information about financial instruments as at December 31, 2018, that are sensitive to changes in interest rates. For long-term debt, the table presents principal payments and related weighted-average interest rates by expected contractual maturity dates. For interest rate swaps, the table presents notional amounts and weighted-average interest rates by expected contractual maturity dates.

	Expected Maturity Date								
	2019	2020	2021	2022	2023	There-after	Total	Fair Value Liability	Rate[1]
	(in millions of U.S. dollars, except percentages)								
Long-Term Debt:									
Variable Rate ($U.S.)[2]	444.3	323.2	273.5	332.6	249.1	263.6	1,886.3	1,864.2	5.1 %
Variable Rate (NOK)[3]	10.0	—	—	—	—	—	10.0	10.0	5.4 %
Variable Rate - Due to affiliates ($U.S.)[4]	125.0	—	—	—	—	—	125.0	122.0	7.6 %
Fixed Rate ($U.S.)	102.1	25.8	29.5	263.7	725.7	99.1	1,245.9	1,186.0	7.3 %
Interest Rate Swaps:									
Contract Amount[5][6]	92.3	446.2	324.6	120.3	16.0	466.7	1,466.1	107.1	3.6 %
Average Fixed Pay Rate[2]	2.8 %	2.9 %	3.9 %	2.2 %	2.9 %	4.6 %	3.6 %		

(1) Rate relating to long-term debt refers to the weighted-average effective interest rate for our debt, including the margin paid on our floating-rate debt. Rate relating to interest rate swaps refers to the average fixed pay rate for interest rate swaps. The average fixed pay rate for interest rate swaps excludes the margin paid on the floating-rate debt, which as of December 31, 2018 ranged between 0.90% and 4.30% based on LIBOR and 4.25% based on NIBOR.

(2) Interest payments on U.S. Dollar-denominated debt and interest rate swaps are based on LIBOR.

(3) Interest payments on NOK-denominated debt and interest rate swaps are based on NIBOR. Our NOK-denominated debt has been economically hedged with cross currency swaps, to swap all interest and principal payments at maturity into U.S. Dollars. Please see the table in the Foreign Currency Fluctuation Risk section below and read Item 18 – Financial Statements: Note 12 – Derivative Instruments.

(4) Includes amounts related to the Brookfield and Teekay Corporation unsecured revolving credit facility.

(5) The average variable receive rate for interest rate swaps is set quarterly at the 3-month LIBOR or semi-annually at the 6-month LIBOR.

(6) Includes three interest rate swaps, which as at December 31, 2018, had a total current notional amount of $451.4 million and a total fair value liability of $69.6 million. These interest rate swaps include early termination provisions, which if exercised, would terminate these interest rate swaps in 2019 or 2021.

Foreign Currency Fluctuation Risk

Our functional currency is the U.S. Dollar because most of our revenues and operating costs are in U.S. Dollars. We incur certain vessel operating expenses, general and administrative expenses and a portion of our capital upgrade projects in foreign currencies, the most significant of which is the Norwegian Krone and, to a lesser extent, the Australian Dollar, Brazilian Real, British Pound, Euro and Singapore Dollar. There is a risk that currency fluctuations will have a negative effect on the value of our cash flows.

We may continue to seek to hedge these currency fluctuation risks in the future. At December 31, 2018, we were committed to the following foreign currency forward contracts:

Expected Maturity

	Contract Amount in Foreign Currency (thousands)	Average Forward Rate(1)	2019	2020	Fair Value / Carrying Amount of Asset (Liability) (in thousands of U.S. Dollars)
			(in thousands of U.S. Dollars)		
Norwegian Krone	425,000	7.96	47,809	5,567	(4,588)
Euro	12,000	0.86	13,977	—	(62)
			61,786	5,567	(4,650)

(1) Average forward rate represents the contracted amount of foreign currency one U.S. Dollar will buy.

We incur interest expense on our NOK-denominated bonds. We have entered into cross currency swaps to economically hedge the foreign exchange risk on the principal and interest for these bonds. Please read Item 18 – Financial Statements: Note 12 – Derivative Instruments.

As at December 31, 2018, we were committed to the following cross currency swap:

Principal Amount NOK (thousands)	Principal Amount USD (thousands)	Floating Rate Receivable Reference Rate	Margin	Fixed Rate Payable	Fair Value / Asset (Liability)	Remaining Term (years)
95,000	15,409	NIBOR	4.25 %	7.45 %	(4,538)	0.1

Commodity Price Risk

We are exposed to changes in forecasted bunker fuel costs for certain vessels being time-chartered-out and for vessels servicing certain contracts of affreightment. We may use bunker fuel swap contracts as economic hedges to protect against changes in bunker fuel costs. As at December 31, 2018, we were not committed to any bunker fuel swap contracts.

Item 12. Description of Securities Other than Equity Securities

Not applicable.

PART II

Item 13. Defaults, Dividend Arrearages and Delinquencies

Not Applicable.

Item 14. Material Modifications to the Rights of Unitholders and Use of Proceeds

Not applicable.

Item 15. Controls and Procedures

We maintain disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the U.S. Securities and Exchange Act of 1934, as amended (or the Exchange Act)) that are designed to ensure that (i) information required to be disclosed in our reports that are filed or submitted under the Exchange Act, are recorded, processed, summarized, and reported within the time periods specified in the U.S. Securities and Exchange Commission's rules and forms, and (ii) information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

We conducted an evaluation of our disclosure controls and procedures under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the Service Provider. Based on the evaluation, the Chief Executive Officer and Chief Financial Officer of the Service Provider concluded that our disclosure controls and procedures are effective as of December 31, 2018.

The Chief Executive Officer and Chief Financial Officer of the Service Provider do not expect that our disclosure controls or internal controls will prevent all errors and all fraud. Although our disclosure controls and procedures were designed to provide reasonable assurance of achieving their objectives, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within us have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based partly on certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

Management's Report on Internal Control over Financial Reporting
Our management is responsible for establishing and maintaining for us adequate internal control over financial reporting.

Our internal controls were designed to provide reasonable assurance as to the reliability of our financial reporting and the preparation and presentation of the consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States. Our internal control over financial reporting includes those policies and procedures that: 1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; 2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of management and the directors;

and 3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

We conducted an evaluation of the effectiveness of our internal control over financial reporting based upon the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements even when determined to be effective and can only provide reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate. However, based on the evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2018.

Our independent auditors, KPMG LLP, an independent registered public accounting firm, has audited the accompanying consolidated financial statements and our internal control over financial reporting. Their attestation report on the effectiveness of our internal control over financial reporting can be found on page F-2 of this Annual Report.

There were no changes in our internal controls that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting (as defined in Rule 13a - 15 (f) under the Exchange Act) that occurred during the year ended December 31, 2018.

Item 16A. Audit Committee Financial Expert

The board of directors of our general partner has determined that director John J. Peacock qualifies as an audit committee financial expert and is independent under applicable NYSE and SEC standards.

Item 16B. Code of Ethics

We have adopted a Standards of Business Conduct Policy that applies to all our employees and the directors of our general partner. This document is available under “Investors – Teekay Offshore Partners L.P. – Governance” from the home page of our web site (www.teekay.com). We intend to disclose, under “Investors – Teekay Offshore Partners L.P. – Governance” in the Investors section of our web site, any waivers to or amendments of the Code of Ethics for the benefit of any directors and executive officers of our general partner.

Item 16C. Principal Accountant Fees and Services

Our principal accountant for 2018 and 2017 was KPMG LLP, Chartered Professional Accountants. The following table shows the fees we paid or accrued for audit services provided by KPMG LLP for 2018 and 2017.

	2018	2017
	(in thousands of U.S. Dollars)	
Audit Fees (1)	$ 2,515	$ 1,927
Audit-Related Fees (2)	30	8
Tax Fees (3)	24	24
Total	$ 2,569	$ 1,959

(1) Audit fees represent fees for professional services provided in connection with the audits of our consolidated financial statements and effectiveness of internal control over financial reporting, review of our quarterly consolidated financial statements and audit services provided in connection with other statutory or regulatory filings, including professional services in connection with the review of our regulatory filings for our follow-on offering of common units and offerings of preferred units.

(2) Audit-related fees relate to other accounting consultations.

(3) For 2018 and 2017, tax fees relate primarily to corporate tax compliance fees.

The Audit Committee of our general partner's board of directors has the authority to pre-approve permissible audit-related and non-audit services not prohibited by law to be performed by our independent auditors and associated fees. Engagements for proposed services either may be separately pre-approved by the Audit Committee or entered into pursuant to detailed pre-approval policies and procedures established by the Audit Committee, as long as the Audit Committee is informed on a timely basis of any engagement entered into on that basis. The Audit Committee separately pre-approved all engagements and fees paid to our principal accountant in 2018.

Item 16D. Exemptions from the Listing Standards for Audit Committees

Mr. Jim Reid, who serves on the Audit Committee of our Board of Directors as an observer, is a Managing Partner and the Chief Investment Officer in Brookfield's Private Equity Group. Affiliates of Brookfield are the largest common unitholder of us and the owner of a 51% interest in our general partner. As an observer, Mr. Reid does not have voting rights on the Audit Committee. He is neither the chair of the Audit

Committee nor an executive officer of us. Accordingly, we rely on the exemption provided in Rule 10A-3(b)(1)(iv)(D) of the U.S. Securities Exchange Act for Mr. Reid's service on the Audit Committee. We do not believe that Mr. Reid's affiliation with Brookfield materially adversely affects the ability of the Audit Committee to act independently or to satisfy the other requirements relating to audit committees contained in Rule 10A-3 under the Exchange Act.

Item 16E. Purchases of Units by the Issuer and Affiliated Purchasers

Not applicable.

Item 16F. Change in Registrant's Certifying Accountant

As reported in our Report on Form 6-K dated as of January 29, 2019, there will be a change in our independent registered public accounting firm for our fiscal year ending December 31, 2019.

Item 16G. Corporate Governance

As a foreign private issuer under SEC rules, we are not required to comply with certain corporate governance practices followed by U.S. publicly traded partnerships under the New York Stock Exchange (or NYSE) listing standards. The following is the significant way in which our corporate governance practices differ from those followed by U.S. limited partnerships listed on the NYSE, and which difference is permitted by NYSE rules for foreign private issuers:

- The NYSE requires that U.S. issuers have an audit committee comprised entirely of independent directors. Our audit committee currently consists of three independent directors and one director (who does not meet the heightened independence standards for audit committee membership), who only has observer status and is a non-voting member of the committee.

Similar to other publicly traded partnerships and as a foreign private issuer, we are not required to obtain unitholder approval prior to the adoption of equity compensation plans or certain equity issuances, including, among others, issuing 20% or more of our outstanding common units or voting power in a transaction.

Item 16H. Mine Safety Disclosure

Not applicable.

PART III

Item 17. Financial Statements

Not applicable.

Item 18. Financial Statements

The following financial statements, together with the related reports of KPMG LLP, Independent Registered Public Accounting Firm thereon, are filed as part of this Annual Report:

All schedules for which provision is made in the applicable accounting regulations of the SEC are not required, are inapplicable or have been disclosed in the Notes to the Consolidated Financial Statements and therefore have been omitted.

Item 19. Exhibits
The following exhibits are filed as part of this Annual Report:

1.1 Certificate of Limited Partnership of Teekay Offshore Partners L.P., dated August 30, 2016. (1)
1.2 Sixth Amended and Restated Agreement of Limited Partnership of Teekay Offshore Partners L.P. (2)
1.3 Certificate of Formation of Teekay Offshore GP L.L.C., dated August 25, 2006.(1)
1.4 Second Amended and Restated Limited Liability Company Agreement of Teekay Offshore GP L.L.C. (3)
1.5 Amendment No. 1 to the Second Amended and Restated Limited Liability Company Agreement of Teekay Offshore GP L.L.C(4)
1.6 Certificate of Limited Partnership of Teekay Offshore Operating L.P., dated September 22, 2006. (1)
1.7 Amended and Restated Agreement of Limited Partnership of Teekay Offshore Operating L.P. (1)
1.8 Certificate of Formation of Teekay Offshore Operating GP L.L.C., dated September 22, 2006 (1)
2.1 Agreement, dated August 18, 2016, between Teekay Offshore Partners L.P. and Citigroup Global Markets Inc. to offer and sell common units having an aggregate offering price of up to $100,000,000 under the Continuous Offering Program. (5)
2.2 Agreement, dated September 8, 2017, for U.S. $600,000,000 Revolving Credit Facility, between Teekay Shuttle Tankers L.L.C. and Den Norske Bank Capital L.L.C. and various other banks(3)
2.3 Agreement, dated July 31, 2015, among OOGTK Libra GmbH & Co KG, ABN AMRO Bank N.V. and various other banks for a U.S. $803,711,786.92 term loan due 2027. (6)
2.4 Agreement, dated February 24, 2014 among Knarr L.L.C., Citibank, N.A. and others, for a U.S. $815,000,000 Secure Term Loan Facility Agreement, of which $614,944,162 is due through 2026, $120,000,000 is due through 2024 and $80,055,838 is due through 2020. (7)
2.5 Indenture, dated as of July 2, 2018, among Teekay Offshore Partners L.P., Teekay Offshore Finance Corp. and The Bank of New York Mellon, as trustee. (8)
2.6 Second Supplemental Indenture, dated as of July 3, 2018, among Teekay Offshore Partners, L.P., Teekay Offshore Finance Corp. and The Bank of New York Mellon, as trustee. (8)
4.1 Teekay Offshore Partners L.P. 2006 Long-Term Incentive Plan. (1)
4.2 Form of Amended and Restated Omnibus Agreement. (1)
4.3 Form of Administrative Services Agreement between Teekay Offshore Operating Partners L.P. and Teekay Shipping Limited.(9)
4.4 Form of Advisory, Technical and Administrative Services Agreement between Teekay Offshore Operating Partners L.P. and Teekay Shipping Limited. (9)
4.5 Form of Administrative Services Agreement between Teekay Offshore Partners L.P. and Teekay Shipping Limited. (9)
4.6 Business Development Services Agreement, dated August 27, 2012, between Teekay Offshore Holdings L.L.C. and Teekay Shipping Limited. (10)
4.7 Registration Rights Agreement, dated June 29, 2016, by and among Teekay Offshore Partners L.P. and the Purchasers Named on Schedule A thereto. (11)
4.8 Registration Rights Agreement, dated June 29, 2016, by and among Teekay Offshore Partners L.P. and the Purchasers Named on Schedule A thereto. (11)
4.9 Warrant Agreement, dated June 29, 2016 by and among Teekay Offshore Partners L.P. and Computershare Inc. and Computershare Trust Company N.A.(11)
4.10 Common Unit Purchase Agreement, dated June 16, 2016, by and among Teekay Offshore Partners L.P. and the Purchasers named on Schedule A thereto (11)
4.11 Series D Preferred Unit Purchase Agreement, dated June 22, 2016, by and among Teekay Offshore Partners L.P. and the Purchasers named on Schedule A thereto (11)
4.12 Investment Agreement, dated as of July 26, 2017, by and between Teekay Offshore Partners L.P. and Brookfield TK TOLP L.P. (12)

4.13 Investment Agreement, dated as of July 26, 2017, between Teekay Offshore Partners L.P. and Teekay Holdings Limited (12)

4.14 Purchase Agreement, dated as of July 26, 2017, between Teekay Holdings Limited and Brookfield TK TOGP L.P. (12)

4.15 Amended and Restated Subordinate Promissory Note, dated as of July 26, 2017, by and between Teekay Offshore Partners L.P., Teekay Corporation and Brookfield TK TOLP L.P. (12)

4.16 Warrant Agreement, dated as of September 25, 2017, by and between Teekay Offshore Partners L.P. and Brookfield TK TOLP L.P. (3)

4.17 Warrant Agreement, dated as of September 25,2017, by and between Teekay Offshore Partners L.P. and Teekay Shipping Limited (3)

4.18 Registration Rights Agreement, dated September 25, 2017, by and between Teekay Offshore Partners L.P., Teekay Corporation and Brookfield TK TOLP L.P. (3)

4.19	Master Services Agreement, dated September 25, 2017, by and between Teekay Corporation, Teekay Offshore Partners L.P. and Brookfield TK TOLP L.P[(3)]
4.20	Trademark License Agreement, dated September 25, 2017, by and between Teekay Corporation and Teekay Offshore Partners L.P. [(3)]
8.1	List of Subsidiaries of Teekay Offshore Partners L.P.
12.1	Rule 13a-14(a)/15d-14(a) Certification of Ingvild Saether, President and Chief Executive Officer of Teekay Offshore Group Ltd.
12.2	Rule 13a-14(a)/15d-14(a) Certification of Jan Rune Steinsland, Chief Financial Officer of Teekay Offshore Group Ltd.
13.1	Teekay Offshore Partners L.P. Certification of Ingvild Saether, President and Chief Executive Officer of Teekay Offshore Group Ltd. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
13.2	Teekay Offshore Partners L.P. Certification of Jan Rune Steinsland, Chief Financial Officer of Teekay Offshore Group Ltd. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
15.1	Consent of KPMG LLP, as independent registered public accounting firm.
15.2	Consolidated Financial Statements of OOG TKP FPSO GmbH & Co KG and subsidiaries.
15.3	Consolidated Financial Statements of OOGTK Libra GmbH & Co KG and subsidiaries.
15.4	Letter of KPMG LLP, dated January 28, 2019, regarding change in independent registered public accounting firm. [(13)]
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

(1) Previously filed as exhibits 3.1, 3.3, 3.4, 3.5, 3.6, 3.7, 3.8, 10.2 and 10.3 to our Registration Statement on Form F-1 (File No. 333-139116), filed with the SEC on December 4, 2006, and hereby incorporated by reference to such Registration Statement.

(2) Previously filed as exhibit 4.1 to our Report on Form 6-K filed on January 23, 2018 (File No. 1-33198), and hereby incorporated by reference to such Report.

(3) Previously filed as exhibits 4.1, 4.2, 4.3, 4.4, 10.5, 10.6 and 10.7 to our Report on Form 6-K (File No. 1-33198), filed with the SEC on November 24, 2017, and hereby incorporated by reference to such Report.

(4) Previously filed as exhibit 4.1 to our Report on Form 6-K (File No. 1-33198), filed with the SEC on July 3, 2018, and hereby incorporated by reference to such Report.

(5) Previously filed as exhibit 1.1 to our Report on Form 6-K (File No. 1-33198), filed with the SEC on August 18, 2016, and hereby incorporated by reference to such Report.

(6) Previously filed as exhibit 2.4 to our Report on Form 6-K (File No. 1-33198), filed with the SEC on August 17, 2015, and hereby incorporated by reference to such Report.

(7) Previously filed as exhibit 2.1 to our Report on Form 6-K (File No. 1-33198), filed with the SEC on November 19, 2015, and hereby incorporated by reference to such Report.

(8) Previously filed as exhibits 4.1 and 4.2 to our Report on Form 6-K (File No. 1-33198), filed with the SEC on July 5, 2018, and hereby incorporated by reference to such Report.

(9) Previously filed as exhibits 10.4, 10.5 and 10.9 to our Amendment No. 1 to Registration Statement on Form F-1 (File No. 333-139116), filed with the SEC on December 8, 2006, and hereby incorporated by reference to such Registration Statement.

(10) Previously filed as exhibit 4.12 to our Annual Report on Form 20-F (File No. 33198), filed with the SEC on April 11, 2013, and hereby incorporated by reference to such Report.

(11)

Previously filed as exhibits 4.1, 4.2, 4.3, 10.1 and 10.2 to our Report on Form 6-K (File No. 1-33198), filed with the SEC on June 30, 2016, and hereby incorporated by reference to such Report.

(12) Previously filed as exhibits 10.1, 10.2, 10.3 and 10.4 to our Report on Form 6-K (File No. 1-33198), filed with the SEC on August 1, 2017, and hereby incorporated by reference to such Report.

(13) Previously filed as exhibit 16.1 to our Report on Form 6-K (File No. 1-33198), filed with the SEC on January 29, 2019, and hereby incorporated by reference to such Report.

SIGNATURE

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

	TEEKAY OFFSHORE PARTNERS L.P. By: Teekay Offshore GP L.L.C., its General Partner
Date: February 28, 2019	By: /s/ Edith Robinson Edith Robinson Secretary

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Unitholders
Teekay Offshore Partners L.P.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Teekay Offshore Partners L.P. and subsidiaries (the Partnership) as of December 31, 2018 and 2017, the related consolidated statements of (loss) income, comprehensive (loss) income, cash flows, and changes in total equity for each of the years in the three year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2018, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2019 expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Partnership has changed its accounting policies for revenue recognition as of January 1, 2018 due to the adoption of ASU 2014-09 - Revenue from Contracts with Customers, and the classification of restricted cash and final settlements on cross currency swap agreements on the statement of cash flows for 2018 and comparative periods due to the adoption of ASU 2016-18 - Statement of Cash Flows: Restricted Cash and ASU 2016-15 - Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments, respectively.

Basis for Opinion

These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP
Chartered Professional Accountants
We have served as the Partnership's auditor since 2011.
Vancouver, Canada
February 28, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Unitholders
Teekay Offshore Partners L.P.

Opinion on Internal Control Over Financial Reporting

We have audited Teekay Offshore Partners L.P. and subsidiaries' (the Partnership) internal control over financial reporting as of December 31, 2018, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Partnership as of December 31, 2018 and 2017, the related consolidated statements of (loss) income, comprehensive (loss) income, cash flows, and changes in total equity for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements), and our report dated February 28, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ KPMG LLP

Chartered Professional Accountants
Vancouver, Canada
February 28, 2019

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF (LOSS) INCOME
(in thousands of U.S. Dollars, except unit and per unit data)

	Year Ended December 31, 2018 $	Year Ended December 31, 2017 $	Year Ended December 31, 2016 $
Revenues (notes 2, 5, and 11)	1,416,424	1,110,284	1,152,390
Voyage expenses (note 2)	(151,808)	(99,444)	(80,750)
Vessel operating expenses (notes 2 and 11)	(437,671)	(353,564)	(364,441)
Time-charter hire expenses	(52,616)	(80,315)	(75,485)
Depreciation and amortization (notes 1 and 2)	(372,290)	(309,975)	(300,011)
General and administrative (notes 11 and 17)	(65,427)	(62,249)	(56,122)
(Write down) and gain (loss) on sale of vessels (note 18)	(223,355)	(318,078)	(40,079)
Restructuring charge (note 10)	(1,520)	(2,664)	(4,649)
Income (loss) from vessel operations	111,737	(116,005)	230,853
Interest expense (notes 8, 11 and 12)	(199,395)	(154,890)	(140,611)
Interest income	3,598	2,707	1,257
Realized and unrealized gain (loss) on derivative instruments (note 12)	12,808	(42,853)	(20,313)
Equity income (notes 2 and 19)	39,458	14,442	17,933
Foreign currency exchange loss (note 12)	(9,413)	(14,006)	(14,805)
Losses on debt repurchases (notes 8 and 11h)	(55,479)	(3,102)	—
Other (expense) income - net (notes 3 and 14b)	(4,602)	14,167	(21,031)
(Loss) income before income tax (expense) recovery	(101,288)	(299,540)	53,283
Income tax (expense) recovery (notes 2 and 13)	(22,657)	98	(8,808)
Net (loss) income	(123,945)	(299,442)	44,475
Non-controlling interests in net (loss) income	(7,161)	3,764	11,858
Preferred unitholders' interest in net (loss) income (note 16)	31,485	42,065	45,836
General Partner’s interest in net (loss) income	(1,128)	(5,770)	(267)
Limited partners' interest in net (loss) income	(147,141)	(339,501)	(12,952)
Limited partners' interest in net (loss) income for basic net (loss) income per common unit (note 16)	(147,141)	(320,749)	(31,326)
Limited partner's interest in net (loss) income per common unit			
- basic (note 16)	(0.36)	(1.45)	(0.25)
- diluted (note 16)	(0.36)	(1.46)	(0.25)
Weighted-average number of common units outstanding:			
- basic	410,261,239	220,755,937	124,747,207
- diluted	410,261,239	229,940,120	124,747,207
Cash distributions declared per common unit	0.04	0.24	0.44

Related party transactions (note 11)
The accompanying notes are an integral part of the consolidated financial statements.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME
(in thousands of U.S. Dollars)

	Year Ended December 31, 2018 $	Year Ended December 31, 2017 $	Year Ended December 31, 2016 $
Net (loss) income	(123,945)	(299,442)	44,475
Other comprehensive income (loss):			
Other comprehensive income (loss) before reclassifications			
Unrealized gain (loss) on qualifying cash flow hedging instruments (note 12)	6,017	(905)	(1,564)
Pension adjustments, net of taxes	1,096	—	—
Amounts reclassified from accumulated other comprehensive income (loss)			
To interest expense:			
Realized (gain) loss on qualifying cash flow hedging instruments (note 12)	(102)	1,186	64
To equity income:			
Realized loss on qualifying cash flow hedging instruments	873	—	—
Other comprehensive income (loss)	7,884	281	(1,500)
Comprehensive (loss) income	(116,061)	(299,161)	42,975
Non-controlling interests in comprehensive (loss) income	(7,161)	3,764	11,858
Preferred unitholders' interest in comprehensive (loss) income	31,485	42,065	45,836
General and limited partners' interest in comprehensive (loss) income	(140,385)	(344,990)	(14,719)

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

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands of U.S. Dollars)

	As at December 31, 2018 $	As at December 31, 2017 $
ASSETS		
Current		
Cash and cash equivalents	225,040	221,934
Restricted cash (notes 3, 12 and 15)	8,540	28,360
Accounts receivable, including non-trade of $8,183 (December 31, 2017 - $32,387) (note 2)	141,903	162,691
Vessels held for sale (note 18)	12,528	—
Prepaid expenses	32,199	30,336
Due from affiliates (note 11l)	58,885	37,376
Other current assets (notes 2, 3b, 5 and 12)	11,879	29,249
Total current assets	490,974	509,946
Vessels and equipment		
At cost, less accumulated depreciation of $1,634,394 (December 31, 2017 - $1,562,172)	4,196,909	4,398,836
Advances on newbuilding contracts and conversion costs (notes 14c and 14e)	73,713	288,658
Investments in equity accounted joint ventures (notes 2 and 19)	212,202	169,875
Deferred tax asset (notes 2 and 13)	9,168	28,110
Due from affiliates (note 11l)	949	—
Other assets (notes 2, 3b, 5 and 12)	198,992	113,225
Goodwill (note 6a)	129,145	129,145
Total assets	5,312,052	5,637,795
LIABILITIES AND EQUITY		
Current		
Accounts payable	16,423	43,317
Accrued liabilities (notes 7, 10, 12, 14, and 17)	129,896	187,687
Deferred revenues	55,750	69,668
Due to affiliates (notes 11h and 11l)	183,795	108,483
Current portion of derivative instruments (note 12)	23,290	42,515
Current portion of long-term debt (note 8)	554,336	589,767
Other current liabilities (note 5)	15,062	9,056
Total current liabilities	978,552	1,050,493
Long-term debt (note 8)	2,543,406	2,533,961
Derivatives instruments (note 12)	94,354	167,469
Due to affiliates (notes 11f and 11l)	—	163,037
Other long-term liabilities (notes 5, 13 and 14)	236,616	249,336
Total liabilities	3,852,928	4,164,296
Commitments and contingencies (notes 8, 9, 12 and 14)		
Redeemable non-controlling interest	—	(29)
Equity		
Limited partners - common units (410.3 million and 410.0 million units issued and outstanding at December 31, 2018 and December 31, 2017, respectively) (notes 2, 16 and 17)	883,090	1,004,077
Limited partners - preferred units (15.8 million and 11.0 million units issued and outstanding at December 31, 2018 and December 31, 2017, respectively) (note 16)	384,274	266,925

General Partner	15,055	15,996
Warrants (note 16)	132,225	132,225
Accumulated other comprehensive income (loss)	7,361	(523)
Non-controlling interests	37,119	54,828
Total equity	1,459,124	1,473,528
Total liabilities and equity	5,312,052	5,637,795

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

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands of U.S. Dollars)

	Year Ended December 31, 2018 $	Year Ended December 31, 2017 $	Year Ended December 31, 2016 $
Cash, cash equivalents and restricted cash provided by (used for)			
OPERATING ACTIVITIES			
Net (loss) income	(123,945)	(299,442)	44,475
Non-cash items:			
Unrealized gain on derivative instruments (note 12)	(53,419)	(59,702)	(44,128)
Equity income, net of dividends received of $6,200 (2017 - $11,600, 2016 - $7,206)	(33,258)	(2,842)	(10,727)
Depreciation and amortization	372,290	309,975	300,011
Write down and (gain) loss on sale of vessels (note 18)	223,355	318,078	40,079
Deferred income tax expense (recovery) (note 13)	18,606	(1,870)	4,854
Amortization of in-process revenue contracts (note 6b)	(35,219)	(12,745)	(12,779)
Other	16,871	37,511	26,812
Change in non-cash working capital items related to operating activities (note 15b)	(83,227)	33,506	74,218
Expenditures for dry docking (note 1)	(21,411)	(17,269)	(26,342)
Net operating cash flow	280,643	305,200	396,473
FINANCING ACTIVITIES			
Proceeds from long-term debt (note 8)	734,698	1,205,477	456,697
Scheduled repayments of long-term debt and settlement of related swaps (notes 8 and 12)	(567,298)	(652,898)	(476,908)
Prepayments of long-term debt and settlement of related swaps (notes 8 and 12)	(457,426)	(702,115)	(197,776)
Debt issuance costs	(14,128)	(17,268)	(12,095)
Equity contribution from joint venture partners	—	6,000	750
Proceeds from issuance of common units and warrants (note 16)	—	640,595	135,246
Proceeds from issuance of preferred units and warrants (note 16)	120,000	—	100,000
Repurchase of preferred units (note 16)	—	(250,022)	—
Expenses relating to equity offerings	(3,997)	(12,155)	(6,395)
Cash distributions paid by the Partnership	(46,675)	(60,593)	(78,634)
Cash distributions paid by subsidiaries to non-controlling interests	(12,048)	(9,891)	(14,210)
Cash contribution paid from non-controlling interest to subsidiaries	1,500	—	—
Proceeds from credit facility due to affiliates (note 11h)	125,000	—	—
Other	(964)	(4,183)	(90)
Net financing cash flow	(121,338)	142,947	(93,415)
INVESTING ACTIVITIES			
Net payments for vessels and equipment, including advances on newbuilding contracts and conversion costs	(233,736)	(533,260)	(294,581)
Proceeds from sale of vessels and equipment (note 18)	30,049	13,100	69,805
Investments in equity accounted joint ventures	(3,000)	(25,824)	(54,873)
Direct financing lease payments received (investments)	5,414	5,844	(115)
Acquisition of companies from Teekay Corporation (net of cash acquired of $26.6m) (note 11k)	25,254	—	—
Net investing cash flow	(176,019)	(540,140)	(279,764)

(Decrease) increase in cash, cash equivalents and restricted cash	(16,714)	(91,993)	23,294
Cash, cash equivalents and restricted cash, beginning of the year	250,294	342,287	318,993
Cash, cash equivalents and restricted cash, end of the year	233,580	250,294	342,287

Supplemental cash flow disclosure (note 15)

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

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN TOTAL EQUITY
(in thousands of U.S. Dollars and units)

	PARTNERS' EQUITY										
	Limited Partners										
	Common Units #	Common Units and Additional Paid-in Capital $	Preferred Units #	Preferred Units $	Warrants $	General Partner $	Accumulated Other Comprehensive Income (Loss) $	Non-controlling Interests $	Total Equity $	Convertible Preferred Units #	Convertible Preferred Units $
Balance as at December 31, 2015	107,027	629,264	11,000	266,925	—	17,608	696	53,355	967,848	10,438	252,498
Net income	—	(12,952)	—	21,500	—	(267)	—	9,469	17,750	—	24,336
Other comprehensive loss (note 12)	—	—	—	—	—	—	(1,500)	—	(1,500)	—	—
Cash distributions	—	(45,904)	—	(21,500)	—	(480)	—	(9,610)	(77,494)	—	(10,750)
Payment-in-kind distributions (note 16)	4,558	15,869	—	—	—	(630)	—	—	15,239	—	(12,739)
Contributions of capital from joint venture partner	—	—	—	—	—	—	—	750	750	—	—
Contribution of capital from Teekay Corporation (note 11g)	—	3,592	—	—	—	73	—	—	3,665	—	—
Proceeds from equity offerings, net of offering costs (note 16)	27,504	127,957	—	—	13,797	3,058	—	—	144,812	4,000	83,453
Conversion of Convertible Preferred Units (note 16)	8,324	46,282	—	—	—	889	—	—	47,171	(1,921)	(46,429)
Exchange of Convertible Preferred Units (note 16)	—	20,231	—	—	—	413	—	—	20,644	—	(20,644)
Equity based compensation and other (note 17)	101	(283)	—	—	—	(6)	—	—	(289)	—	1,512
	147,514	784,056	11,000	266,925	13,797	20,658	(804)	53,964	1,138,596	12,517	271,237

Balance as at December 31, 2016											
Net loss	—	(339,501)	—	21,500	—	(5,770)	—	3,711	(320,060)	—	20,565
Other comprehensive income (note 12)	—	—	—	—	—	—	281	—	281	—	—
Cash distributions	—	(28,857)	—	(21,500)	—	(31)	—	(8,847)	(59,235)	—	(10,205)
Payment-in-kind distributions (note 16)	6,391	19,687	—	—	—	(699)	—	—	18,988	—	(14,022)
Contributions of capital from joint venture partner	—	—	—	—	—	—	—	6,000	6,000	—	—
Contribution of capital from Teekay Corporation (notes 11g and 16)	—	44,442	—	—	—	873	—	—	45,315	—	—
Proceeds from equity offerings, net of offering costs (note 16)	256,000	504,851	—	—	119,948	588	—	—	625,387	—	—
Repurchase of Convertible Preferred Units (note 16)	—	19,588	—	—	—	383	—	—	19,971	(12,517)	(269,993)
Equity based compensation and other (note 17)	140	(189)	—	—	(1,520)	(6)	—	—	(1,715)	—	2,418
Balance as at December 31, 2017	410,045	1,004,077	11,000	266,925	132,225	15,996	(523)	54,828	1,473,528	—	—
Net loss	—	(147,141)	—	31,485	—	(1,128)	—	(7,161)	(123,945)	—	
Other comprehensive income (note 12)	—	—	—	—	—	—	7,884	—	7,884	—	
Cash distributions	—	(16,410)	—	(30,139)	—	(126)	—	(12,048)	(58,723)	—	
Contribution from non-controlling interests	—	—	—	—	—	—	—	1,500	1,500	—	
Proceeds from equity offerings,	—	—	4,800	116,003	—	—	—	—	116,003	—	

net of offering costs (note 16)											
Change in accounting policy (note 2)	—	41,381	—	—	—	316	—	—	41,697	—	
Equity based compensation and other (note 17)	270	1,183	—	—	—	(3)	—	—	1,180	—	
Balance as at December 31, 2018	410,315	883,090	15,800	384,274	132,225	15,055	7,361	37,119	1,459,124	—	—

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

1. Summary of Significant Accounting Policies

Basis of presentation

The consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (or GAAP). These financial statements include the accounts of Teekay Offshore Partners L.P., which is a limited partnership organized under the laws of the Republic of the Marshall Islands, and its wholly owned or controlled subsidiaries (collectively, the Partnership). Unless the context otherwise requires, the terms "we," "us," or "our," as used herein, refer to the Partnership.

The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results may differ from those estimates.

Foreign currency

The consolidated financial statements are stated in U.S. Dollars and the functional currency of the Partnership is the U.S. Dollar. Transactions involving other currencies during the year are converted into U.S. Dollars using the exchange rates in effect at the time of the transactions. At the balance sheet dates, monetary assets and liabilities that are denominated in currencies other than the U.S. Dollar are translated to reflect the year-end exchange rates. Resulting gains or losses are reflected separately in the accompanying consolidated statements of (loss) income.

Revenues

Each vessel charter may, depending on its terms, contain a lease component, a non-lease component or both. Revenues that are fixed on or prior to the commencement of the contract are recognized by the Partnership on a straight-line basis daily over the term of the contract. Where the term of the contract is based on the duration of a single voyage, the Partnership uses a discharge-to-discharge basis in determining proportionate performance for all tanker spot voyages that contain a lease and a load-to-discharge basis in determining proportionate performance for all tanker spot voyages that do not contain a lease. Consequently, the Partnership does not begin recognizing revenue until a voyage charter has been agreed to by the customer and the Partnership, even if the vessel has discharged its prior cargo and is sailing to the anticipated load location for its next voyage. For towage voyages, proportionate performance is determined based on commencement of the tow to completion of the tow. Reimbursements of vessel operating expenditures incurred to provide the contracted services to the charterer are recognized when the expenses entitling the Partnership to reimbursement are incurred. Revenue or penalties from performance-based metrics, such as production tariffs and other operational performance measures, are recognized as earned or incurred unless such performance-based revenue is based on a multi-period performance-based metric that is allocable to non-lease services provided. In such a case, the Partnership will estimate the amount of variable consideration, to the extent that it is probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved and recognize such estimate of revenue over the performance period.

The consolidated balance sheets reflect in other current assets the accrued portion of revenues for those voyages that commence prior to balance sheet date and complete after the balance sheet date and reflect in deferred revenues or other long-term liabilities the deferred portion of revenues which will be earned in subsequent periods.

Operating expenses

Voyage expenses are all expenses unique to a particular voyage, including bunker fuel expenses, port fees, cargo loading and unloading expenses, canal tolls, agency fees and commissions. Vessel operating expenses include crewing, ship management services, repairs and maintenance, insurance, stores, lube oils and communication expenses.

Voyage expenses and vessel operating expenses are recognized when incurred except when the Partnership incurs pre-operational costs related to the repositioning of a vessel or offshore unit that relates directly to a specific customer contract, that generates or enhances resources of the Partnership that will be used in satisfying performance obligations in the future, and where such costs are expected to be recovered via the customer contract. In this case, such costs are deferred and amortized over the duration of the customer contract.

The Partnership recognizes the expense from vessels time-chartered from other owners, which is included in time-charter hire expenses in the accompanying consolidated statements of (loss) income, on a straight-line basis over the firm period of the charters.

Cash and cash equivalents

The Partnership classifies all highly-liquid investments with a maturity date of three months or less when purchased as cash and cash equivalents.

Accounts receivable and allowance for doubtful accounts

Accounts receivable are recorded at the invoiced amount and do not bear interest. The allowance for doubtful accounts is the Partnership's best estimate of the amount of probable credit losses in existing accounts receivable. The Partnership determines the allowance based on historical write-off experience and customer economic data. The Partnership reviews the allowance for doubtful accounts regularly and past due balances are reviewed for collectability. Account balances are charged against the allowance when the Partnership believes that the receivable will not be recovered. There is no allowance for doubtful accounts recorded as at December 31, 2018 and 2017.

Investments in equity accounted joint ventures

The Partnership’s investments in equity accounted joint ventures are accounted for using the equity method of accounting. Under the equity method of accounting, the initial cost of the investment is adjusted for subsequent additional investments and the Partnership’s proportionate share of earnings or losses and distributions. The Partnership evaluates its investments in joint ventures for impairment when events or circumstances indicate that the carrying value of such investments may have experienced an other-than-temporary decline in value below carrying value. If the estimated fair value is less than the carrying value, the carrying value is written down to its estimated fair value and the resulting impairment is recorded in the Partnership’s consolidated statements of (loss) income.

Vessels and equipment

All pre-delivery costs incurred during the construction of newbuildings and conversions, including interest, supervision and technical costs, are capitalized. The acquisition cost and all costs incurred to restore used vessels purchased by the Partnership to the standards required to properly service the Partnership’s customers are capitalized.

Vessel capital modifications include the addition of new equipment or can encompass various modifications to the vessel which are aimed at improving and/or increasing the operational efficiency and functionality of the asset. This type of expenditure is amortized over the estimated useful life of the modification. Expenditures covering recurring routine repairs or maintenance are expensed as incurred.

The Partnership's shuttle tankers are comprised of two components: i) a conventional tanker (or the tanker component) and ii) specialized shuttle equipment (or the shuttle component). The Partnership differentiates these two components on the principle that a shuttle tanker can also operate as a conventional tanker without the use of the shuttle component. The economics of this alternate use depend on the supply and demand fundamentals in the two segments. Historically, the Partnership assessed the useful life of the tanker component as being 25 years and the shuttle component as being 20 years. During the year ended December 31, 2018, the Partnership considered challenges associated with shuttle tankers approaching 20 years of age in recent years and reassessed the useful life of the tanker component to 20 years. This change in estimate, which commenced as of January 1, 2018, affected 21 vessels in the Partnership's shuttle tanker fleet. The effect of this change in estimate was an increase in depreciation and amortization expense and net loss of $15.7 million, or $0.04 per basic and diluted common unit, for the year ended December 31, 2018.
Depreciation is calculated on a straight-line basis over a vessel’s estimated useful life to an estimated residual value. Floating production storage and offloading (or FPSO) units are depreciated using an estimated useful life of 20 to 25 years commencing the date the unit is installed at the oil field and is in a condition that is ready to operate. Some of the Partnership’s FPSO units have oil field specific equipment, which is depreciated over the expected life of the oil field. Floating storage and off take (or FSO) units are depreciated over the estimated contract term or the estimated useful life of the specific unit. The unit for maintenance and safety (or UMS) is depreciated over an estimated useful life of 35 years commencing the date it arrived at the oil field and was in a condition that was ready to operate. Towage and offshore installation vessels are depreciated over an estimated useful life of 25 years commencing the date the vessel is delivered from the shipyard. Depreciation of vessels and equipment for the years ended December 31, 2018, 2017 and 2016, totaled $348.4 million, $286.1 million, and $281.2 million, respectively. Depreciation and amortization includes depreciation on all owned vessels.

Interest costs capitalized to vessels and equipment for the years ended December 31, 2018, 2017 and 2016 totaled $11.1 million, $29.6 million and $27.1 million, respectively.

Generally, the Partnership dry docks each shuttle tanker and towage vessel every two and a half to five years. UMS, FSO and FPSO units are generally not dry docked. The Partnership capitalizes a portion of the costs incurred during dry docking and amortizes those costs on a straight-line basis from the completion of a dry docking over the estimated useful life of the dry dock. Included in capitalized dry docking are costs incurred as part of the dry docking to meet regulatory requirements, or expenditures that either add economic life to the vessel, increase the vessel's earning capacity or improve the vessel's operating efficiency. The Partnership expenses costs related to routine repairs and maintenance performed during dry docking that do not improve operating efficiency or extend the useful lives of the assets.

Dry-docking activity for the three years ended December 31, 2018, 2017 and 2016 is summarized as follows:

	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
	$	$	$
Balance at beginning of the year	42,829	49,238	42,822
Cost incurred for dry-docking	23,602	17,183	25,043
Dry-docking amortization	(23,893)	(22,870)	(18,627)
Write down / sale of vessels with capitalized dry-dock expenditure	—	(722)	—
Balance at end of the year	42,538	42,829	49,238

F- 9

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

Vessels and equipment that are “held and used” are assessed for impairment when events or circumstances indicate the carrying amount of the asset may not be recoverable. If the asset’s net carrying value exceeds the net undiscounted cash flows expected to be generated over its remaining useful life, the carrying amount of the asset is reduced to its estimated fair value. The estimated fair value for the Partnership’s impaired vessels is determined using discounted cash flows or appraised values. In cases where an active second hand sale and purchase market does not exist, the Partnership uses a discounted cash flow approach to estimate the fair value of an impaired vessel. In cases where an active second hand sale and purchase market exists, an appraised value is used to estimate the fair value of an impaired vessel. An appraised value is generally the amount the Partnership would expect to receive if it were to sell the vessel. Such appraisal is normally completed by the Partnership. When an asset impairment occurs, the Partnership adjusts the carrying value of the asset to its new cost base and writes off the asset's accumulated depreciation.

Asset retirement obligation

The Partnership has an asset retirement obligation (or ARO) relating to the sub-sea mooring and riser system associated with the Randgrid FSO unit. This obligation involves the costs associated with the restoration of the environment surrounding the facility and removal of all equipment, which are subsequently to be reimbursed by the charterer. This obligation is expected to be settled at the end of the contract under which the FSO unit operates, which is currently estimated to be May 2024.

The Partnership records the fair value of an ARO as a liability in the period when the obligation arises. The fair value of the ARO is measured using expected future cash outflows discounted at the Partnership’s credit-adjusted risk-free interest rate. When the liability is recorded, and as the ARO will be covered by contractual payments to be received from the charterer, the Partnership records a separate receivable concurrently with the ARO being created. Each period, the liability is increased for the change in its present value. Changes in the amount or timing of the estimated ARO are recorded as an adjustment to the related liability and asset. As at December 31, 2018, the ARO and associated receivable, which are recorded in other long-term liabilities and other non-current assets, respectively, were both $24.7 million (2017 - $23.1 million).

Debt issuance costs

Debt issuance costs related to a recognized debt liability, including bank fees, commissions and legal expenses, are capitalized and amortized over the term of the relevant loan facility to interest expense using an effective interest rate method. Debt issuance costs are presented as a reduction from the carrying amount of that debt liability, unless no amounts have been drawn under the debt liability or the debt issuance costs exceed the carrying value of the related debt liability, in which case the debt issuance costs are presented as other non-current assets.

Fees paid to amend a non-revolving credit facility are associated with the extinguishment of the old debt instrument and included in determining the debt extinguishment gain or loss to be recognized. Any unamortized debt issuance costs would be written off. If a debt amendment is considered not to be a substantial amendment, then the fees would be associated with the replacement or modified debt instrument and, along with any existing unamortized debt issuance costs and premium or discount, would be amortized as an adjustment of interest expense over the remaining term of the replacement or modified debt instrument using the effective interest method. Other related costs incurred with third parties directly related to the modification, other than the loan amendment fee, are expensed as incurred.

Fees paid to amend revolving credit facilities are deferred and amortized over the term of the modified credit facility. If the borrowing capacity is increased as a result of the amendment, unamortized loan costs of the original facility would be deferred and amortized over the term of the modified credit facility. If the borrowing capacity is decreased as a result of the amendment, a proportionate amount, based on the reduction in borrowing capacity, of the unamortized debt issuance costs of the original facility would be written off and the remaining amount would be deferred and amortized over the term of the modified credit facility.

Goodwill

Goodwill is not amortized, but reviewed for impairment at the reporting unit level on an annual basis or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. When goodwill is reviewed for impairment, the Partnership will measure the amount by which a reporting unit’s carrying value exceeds its fair value, with the maximum impairment not to exceed the carrying value of goodwill.

Derivative instruments

All derivative instruments are initially recorded at fair value as either assets or liabilities in the accompanying consolidated balance sheets and subsequently remeasured to fair value, regardless of the purpose or intent for holding the derivative. The method of recognizing the resulting gain or loss is dependent on whether the derivative contract is designed to hedge a specific risk and also qualifies and is designated for hedge accounting. During the years ended December 31, 2018 and 2017, certain of the Partnership's interest rate swaps were designated in qualifying hedging relationships and hedge accounting was applied in the consolidated financial statements or within the Partnership's equity-accounted joint ventures (see note 12).

When a derivative is designated in a cash flow hedge, the Partnership formally documents the relationship between the derivative and the hedged item. This documentation includes the strategy and risk management objective for undertaking the hedge and the method that will be used to assess the effectiveness of the hedge. Any hedge ineffectiveness is recognized immediately in earnings, as are any gains and losses on the derivative that are excluded from the assessment of hedge effectiveness. The Partnership does not apply hedge accounting if it is determined that the hedge was not effective or will no longer be effective, the derivative was sold or exercised, or the hedged item was sold, repaid or is no longer probable of occurring. As at December 31, 2018, the Partnership has de-designated all hedging relationships and does not apply hedge accounting to any of its derivative instruments.

For derivative financial instruments designated in qualifying cash flow hedges, changes in the fair value of the effective portion of the derivative financial instruments are initially recorded as a component of accumulated other comprehensive income in equity. In the periods when the hedged items affect earnings, the associated fair value changes on the hedging derivatives are transferred from equity to the corresponding earnings line item in the consolidated statements of (loss) income. The ineffective portion of the change in fair value of the derivative financial instruments is immediately recognized in the interest expense line of the consolidated statements of (loss) income. A portion of the ineffectiveness of the fair value of derivative instruments is recognized in the equity accounted joint ventures line of the consolidated balance sheets. If a cash flow hedge is de-desiganted and the originally hedged item is still considered probable of occurring, the gains and losses initially recognized in equity remain there until the hedged item impacts earnings, at which point they are transferred to the corresponding earnings line item in the consolidated statements of (loss) income. If the hedged item is no longer probable of occurring, amounts recognized in equity are immediately transferred to the relevant earnings line item in the consolidated statements of (loss) income.

For derivative financial instruments that are not designated as accounting hedges, the changes in the fair value of the derivative financial instruments are recognized in earnings. Gains and losses from the Partnership’s non-designated foreign currency forward contracts and interest rate swaps are recorded in realized and unrealized loss on derivative instruments in the consolidated statements of (loss) income. Gains and losses from the Partnership’s non-designated cross currency swaps are recorded in foreign currency exchange loss in the consolidated statements of (loss) income.

Unit-based compensation

The Partnership grants restricted unit-based compensation awards as incentive-based compensation to certain employees of the Partnership and Teekay Corporation’s subsidiaries that provide services to the Partnership (see note 17). The Partnership measures the cost of such awards using an option pricing model to determine the grant date fair value of the award and recognizes that cost, net of estimated forfeitures, over the requisite service period. The requisite service period consists of the period from the grant date of the award to the earlier of the date of vesting or the date the recipient becomes eligible for retirement. For unit-based compensation awards subject to graded vesting, the Partnership calculates the value of the award as if it was one single award with one expected life and amortizes the calculated expense for the entire award on a straight-line basis over the requisite service period. Certain of these awards are cash settled. For cash settled awards, the fair value of such awards is remeasured at each reporting date, based on the fair market value of the Partnership's common units at that date, with the change in fair value recognized as compensation expense. Unit-based compensation expenses are recorded under general and administrative expenses in the Partnership’s consolidated statements of (loss) income.

Income taxes

The Partnership is subject to income taxes relating to its subsidiaries in Norway, Australia, Brazil, the United Kingdom, Singapore, Qatar, Canada, Luxembourg and the Netherlands. The Partnership accounts for such taxes using the liability method. Under the liability method, deferred tax assets and liabilities are recognized for the anticipated future tax effects of temporary differences between the financial statement basis and the tax basis of the Partnership’s assets and liabilities using the applicable jurisdictional tax rates. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized.

Recognition of uncertain tax positions is dependent upon whether it is more-likely-than-not that a tax position taken or expected to be taken in a tax return will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If a tax position meets the more-likely-than-not recognition threshold, it is measured to determine the amount of benefit to recognize in the consolidated financial statements based on guidance in the interpretation. The Partnership recognizes interest and penalties related to uncertain tax positions in income tax recovery (expense) in the Partnership's consolidated statements of (loss) income.

Employee pension plans

On January 1, 2018, the Partnership acquired a 100% ownership interest in seven subsidiaries of Teekay Corporation. These subsidiaries provide ship management, commercial, technical, strategic, business development and administrative services to the Partnership, primarily related to the Partnership's FPSO units, shuttle tankers and FSO units (see note 11j). Employees of these companies are generally eligible to participate in pension plans.

The Partnership has defined contribution pension plans covering the majority of its employees. Pension costs associated with the Partnership's required contributions under its defined contribution pension plans are based on a percentage of employees' salaries and are charged to earnings in the year incurred. With the exception of certain of the Partnership's employees in Norway, the Partnership's employees are generally eligible to participate in defined contribution plans. These plans allow for the employees to contribute a certain percentage of their base salaries into the plans. The Partnership matches all or a portion of the employees' contributions, depending on how much each employee contributes. During the year ended December 31, 2018, the amount of cost recognized for the Partnership's defined contribution pension plans was $4.5 million (December 31, 2017 and 2016 - nil).

The Partnership also has defined benefit pension plans covering 443 active and retired employees in Norway. The Partnership accrues the costs and related obligations associated with its defined benefit pension plans based on actuarial computations using the projected benefits obligation method and management's best estimates of expected plan investment performance, salary escalation, and other relevant factors. For the purpose of calculating the expected return on plan assets, those assets are valued at fair value. The overfunded or underfunded status of the defined benefit pension plans is recognized as assets or liabilities in the consolidated balance sheets. The Partnership recognizes as

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

a component of other comprehensive loss, the gains or losses that arise during a period but that are not recognized as part of net periodic benefit costs. The pension assets have been guaranteed a minimum rate of return by the provider, thus reducing potential exposure to the Partnership to the extent the provider honors its obligations. The Partnership's funded status deficiency relating to its defined benefit pension plans was $1.5 million as at December 31, 2018 (December 31, 2017 - nil).

2. Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (or FASB) issued Accounting Standards Update 2014-09, Revenue from Contracts with Customers (or ASU 2014-09). ASU 2014-09 requires an entity to recognize revenue when it transfers promised goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This update creates a five-step model that requires entities to exercise judgment when considering the terms of the contract(s) which include (i) identifying the contract(s) with the customer, (ii) identifying the separate performance obligations in the contract, (iii) determining the transaction price, (iv) allocating the transaction price to the separate performance obligations, and (v) recognizing revenue as each performance obligation is satisfied. ASU 2014-09 was adopted by the Partnership January 1, 2018, and has been applied, at the Partnership's option, as a cumulative-effect adjustment as of the date of adoption. The Partnership has elected to apply ASC 2014-09 only to those contracts that were not completed as of January 1, 2018. The Partnership identified the following differences:

- Voyage revenues from towage and offshore installation vessels are recognized over the period where the tow is being performed instead of the period of the tow and the mobilization and demobilization of the towage vessel. The cumulative-effect adjustment on January 1, 2018 and the impact for the year ended December 31, 2018 was insignificant.
- Revenue from time-charter contracts with fixed annual increases in the daily hire rate during the firm period of the charter to compensate for expected inflationary cost increases are recognized on a smoothed basis over the term of the time-charter, instead of recognized when due under the contract. For time-charters with a termination fee owing if the contract is not extended past the contract term, the non-lease portion of such termination fee is recognized over the contract term, instead of recognized when the termination fee is incurred. These changes had the impact of increasing revenue by $2.9 million for the year ended December 31, 2018, as well as increasing other assets by $11.4 million, decreasing deferred tax assets by $0.9 million and increasing equity by $10.5 million as at December 31, 2018. The cumulative-effect adjustment on January 1, 2018 was an increase to equity of $7.7 million.
- In certain cases, the Partnership incurs pre-operational costs that relate directly to a specific customer contract, that generate or enhance resources of the Partnership that will be used in satisfying performance obligations in the future, whereby such costs are expected to be recovered via the customer contract. Such costs are deferred and amortized over the duration of the customer contract. The Partnership previously expensed such costs as incurred unless the costs were directly reimbursable by the contract or if they were related to the mobilization of offshore assets to an oil field. This change had the impact of decreasing (increasing) voyage expenses by $1.8 million, vessel operating expenses by $(2.6) million, depreciation and amortization by $1.1 million and equity income by $0.6 million for the year ended December 31, 2018, as well as increasing other assets by $27.8 million, investments in equity accounted joint ventures by $1.2 million, and equity by $29.0 million as at December 31, 2018. The cumulative increase to opening equity as at January 1, 2018 was $29.4 million.
- The Partnership manages FPSO units owned by Teekay Corporation and other vessels. Upon the adoption of ASU 2014-09, costs incurred by the Partnership for its onshore staff and seafarers are presented as vessel operating expenses and the reimbursement of such expenses are presented as revenue, instead of such amounts being presented on a net basis. This had the impact of increasing revenues and vessel operating expenses by $41.2 million for the year ended December 31, 2018. There was no cumulative impact to opening equity as at January 1, 2018.

- Operating costs for the Partnership's Volatile Organic Compounds (or VOC) plants on certain shuttle tankers are presented as vessel operating expenses and the reimbursement of such expenses are presented as revenue instead of such amounts being presented on a net basis. This had the impact of increasing revenues and vessel operating expenses by $8.3 million for the year ended December 31, 2018. There was no cumulative impact to opening equity as at January 1, 2018.
- The Partnership previously presented the net allocation for its vessels participating in revenue sharing arrangements as revenues. The Partnership has determined that it is the principal in voyages its vessels perform that are included in the revenue sharing arrangements. As such, the revenue from those voyages is presented in voyage revenues and the difference between this amount and the Partnership's net allocation from the revenue sharing arrangement is presented as voyage expenses. This had the impact of increasing revenues and voyage expenses by $13.1 million for the year ended December 31, 2018. There was no cumulative impact to opening equity as at January 1, 2018.
- The Partnership previously presented all accrued revenue as a component of accounts receivable. The Partnership has determined that if the right to such consideration is conditional upon something other than the passage of time before payment of that consideration is due, such accrued revenue should be presented apart from accounts receivable. This had the impact of increasing other current assets and decreasing accounts receivable by $5.7 million at December 31, 2018. There was no cumulative impact to opening equity as at January 1, 2018.
- Deferred costs have presented solely as a long-term asset if the remaining charter contract is more than one year or presented solely as a short-term asset if the charter contract is less than one year. This had the impact of decreasing other current assets and increasing long term assets by $14.5 million as at December 31, 2018. There was no cumulative impact to opening equity as at January 1, 2018.

In August 2016, the FASB issued Accounting Standards Update 2016-15, Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments (or ASU 2016-15), which, among other things, provides guidance on two acceptable approaches of classifying distributions received from equity method investees in the statements of cash flows and application of the predominance principle on the cash flow statement classification of cash receipts and payments that have aspects of more than one class of cash flows. ASU 2016-15 became effective for the Partnership January 1, 2018, with a retrospective approach required on adoption. The Partnership has elected to classify distributions received from equity method investees in the statement of cash flows based on the nature of the distribution. In addition, the adoption of ASU 2016-15 resulted in $37.3 million of cross currency swap payments that were related to the principal prepayment or repayment of long-term debt for the year ended December 31, 2018 (December 31, 2017 - $66.7 million and December 31, 2016 - $42.3 million), being reclassified from a net operating cash outflow to a prepayment or repayment of long-term debt in net financing cash flow as the amounts related entirely or predominantly to the termination or final settlement of the cross currency swaps.

In November 2016, the FASB issued Accounting Standards Update 2016-18, Statement of Cash Flows: Restricted Cash (or ASU 2016-18). ASU 2016-18 requires that the statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Entities are also required to reconcile such total to amounts on the balance sheet and disclose the nature of the restrictions. ASU 2016-18 became effective for the Partnership January 1, 2018. Adoption of ASU 2016-18 resulted in the Partnership including in its statement of cash flows changes in cash, cash equivalents and restricted cash.

In August 2018, the FASB issued Accounting Standards Update 2018-15, Intangibles-Goodwill and Other-Internal Use Software: Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract, (or ASU 2018-15). ASU 2018-15 aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. ASU 2018-15 is effective for annual and interim periods beginning after December 15, 2019, with early adoption permitted. This update was adopted by the Partnership on October 1, 2018. There was no impact on transition from the adoption of this update.

In October 2017, the FASB issued Accounting Standards Update 2017-04, Simplifying the Test for Goodwill Impairment. Pursuant to this update, goodwill impairment will now be measured as the amount by which a reporting unit’s carrying value exceeds its fair value, not to exceed the carrying value of goodwill. This update eliminates existing guidance that required an entity to determine goodwill impairment by calculating the implied fair value of goodwill by hypothetically assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. This update was adopted by the Partnership on October 1, 2018. There was no impact on transition from the adoption of this update.

In February 2016, the FASB issued Accounting Standards Update 2016-02, Leases (or ASU 2016-02). ASU 2016-02 establishes a right-of- use model that requires a lessee to record a right of use asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. For lessees, leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. ASU 2016-02 requires lessors to classify leases as a sales-type, direct financing, or operating lease. A lease is a sales-type lease if any one of five criteria are met, each of which indicate that the lease, in effect, transfers control of the underlying asset to the lessee. If none of those five criteria are met, but two additional criteria are both met, indicating that the lessor has transferred substantially all of the risks and benefits of the underlying asset to the lessee and a third party, the lease is a direct financing lease. All leases that are not sales-type leases or direct financing leases are operating leases. ASU 2016-02 is effective January 1, 2019, with early adoption permitted. FASB issued an additional accounting standards update in July 2018 that made further amendments to accounting for leases, including allowing the use of a transition approach whereby a cumulative effect adjustment is made as of the effective date, with no retrospective effect. The Partnership has elected to use this new optional transition approach. The Partnership will adopt ASU 2016-02 on January 1, 2019. To determine the cumulative effect adjustment, the Partnership will not reassess whether any expired or existing contracts are, or contain leases, will not reassess lease classification, and will not reassess initial direct costs for any existing leases. The adoption of ASU 2016-02 will result in a change in the accounting method for the lease portion of the daily charter hire for the Partnership's chartered-in vessels accounted for as operating leases with firm periods of greater than one year. As of December 31, 2018, the Partnership had four in-chartered vessels in its fleet, the accounting for three of which vessels will be impacted by the adoption of ASU 2016-02 as well as a small number of office leases. Under ASU 2016-02, the Partnership will recognize a right-of-use asset and a lease liability on the balance sheet for these charters and office leases based on the present value of future minimum lease payments, whereas currently no right-of-use asset or lease liability is recognized. The right of use asset and lease liability to be recognized on January 1, 2019 is $19.4 million. The pattern of expense recognition of chartered-in vessels is expected to remain substantially unchanged, unless the right of use asset becomes impaired. In addition, direct financing lease payments received will be presented as an operating cash inflow instead of an investing cash inflow in the statement of cash flows.

In June 2016, the FASB issued Accounting Standards Update 2016-13, Financial Instruments - Credit Losses: Measurement of Credit Losses on Financial Instruments (or ASU 2016-13). ASU 2016-13 replaces the incurred loss impairment methodology with a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. This update is effective for the Partnership January 1, 2020, with a modified-retrospective approach. The Partnership is currently evaluating the effect of adopting this new guidance.

3. Financial Instruments

a) Fair value measurements

The following methods and assumptions were used to estimate the fair value of each class of financial instrument:

Cash and cash equivalents and restricted cash - The fair values of the Partnership’s cash and cash equivalents and restricted cash approximate their carrying amounts reported in the accompanying consolidated balance sheets.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

Contingent consideration liability

In August 2014, the Partnership acquired 100% of the outstanding shares of Logitel Offshore Holding AS (or Logitel), a Norway-based company focused on high-end UMS, from Cefront Technology AS (or Cefront) for $4.0 million. The Partnership paid the purchase price in cash at closing, plus a commitment to pay an additional amount of up to $27.6 million, depending on certain performance criteria. For a description of the performance criteria, please refer to the Partnership's Annual Report on Form 20-F for the year ended December 31, 2015.

The Arendal Spirit UMS was delivered to the Partnership on February 16, 2015. During the second quarter of 2016, the Partnership canceled the UMS construction contracts for its two remaining UMS newbuildings. This was expected to eliminate any future purchase price contingent consideration payments. Consequently, the contingent liability associated with the UMS newbuildings was reversed in the second quarter of 2016. The gain associated with this reversal is included in Other (expense) income - net on the Partnership's consolidated statement of income for the year ended December 31, 2016. In September 2017, CeFront and subsidiaries of the Partnership entered into a settlement agreement relating to this contingent liability (see note 14b).

Changes in the estimated fair value of the Partnership’s contingent consideration liability relating to the acquisition of Logitel, which is measured at fair value on a recurring basis using significant unobservable inputs (Level 3), during the years ended December 31, 2018, 2017 and 2016, are as follows:

	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
	$	$	$
Balance at beginning of period	—	—	(14,830)
Acquisition of Logitel	—	—	—
Settlement of liability	—	—	—
Gain included in Other income (expense) - net	—	—	14,830
Balance at end of period	—	—	—

Derivative instruments – The fair value of the Partnership’s derivative instruments is the estimated amount that the Partnership would receive or pay to terminate the agreements at the reporting date, taking into account current interest rates, foreign exchange rates and the current credit worthiness of both the Partnership and the derivative counterparties. The estimated amount is the present value of future cash flows. The Partnership transacts all of its derivative instruments through investment-grade rated financial institutions at the time of the transaction. The Partnership’s interest rate swap agreements and foreign currency forward contracts require no collateral from these institutions; however, collateral is required by these institutions on some of the Partnership’s cross currency swap agreements and as at December 31, 2018 the Partnership had pledged $1.2 million of cash as collateral (2017 - $4.1 million), which has been recorded as restricted cash on the Partnership's consolidated balance sheets.

Long-term debt – The fair value of the Partnership’s fixed-rate and variable-rate long-term debt is either based on quoted market prices or estimated using discounted cash flow analysis based on rates currently available for debt with similar terms and remaining maturities and the current credit worthiness of the Partnership.

The Partnership categorizes its fair value estimates using a fair value hierarchy based on the inputs used to measure fair value. The fair value hierarchy has three levels based on the reliability of the inputs used to determine fair value as follows:

Level 1.Observable inputs such as quoted prices in active markets;
Level 2.Inputs, other than the quoted prices in active markets, that are observable either directly or indirectly; and
Level 3.Unobservable inputs in which there is little or no market data, which require the reporting entity to develop its own assumptions.

The following table includes the estimated fair value and carrying value of those assets and liabilities that are measured at fair value on a recurring and non-recurring basis, as well as the estimated fair value of the Partnership's financial instruments that are not accounted for at fair value on a recurring basis:

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

	Fair Value Hierarchy Level	December 31, 2018 Carrying Amount Asset (Liability) $	December 31, 2018 Fair Value Asset (Liability) $	December 31, 2017 Carrying Amount Asset (Liability) $	December 31, 2017 Fair Value Asset (Liability) $
Recurring:					
Cash and cash equivalents and restricted cash	Level 1	233,580	233,580	250,294	250,294
Derivatives instruments (note 12)					
Interest rate swap agreements	Level 2	(107,074)	(107,074)	(168,247)	(168,247)
Cross currency swap agreement	Level 2	(4,538)	(4,538)	(44,006)	(44,006)
Foreign currency forward contracts	Level 2	(4,650)	(4,650)	(357)	(357)
Other:					
Long-term debt - public (note 8)	Level 1	(1,027,696)	(977,917)	(666,427)	(671,635)
Long-term debt - non-public (note 8)	Level 2	(2,070,046)	(2,082,316)	(2,457,301)	(2,475,946)
Due to affiliates - current (note 11h)	Level 2	(125,000)	(123,025)	—	—
Due to affiliates - long term (note 11f)	Level 2	—	—	(163,037)	(210,089)

b) Financing receivables

The following table contains a summary of the Partnership's financing receivables by type of borrower and the method by which the Partnership monitors the credit quality of its financing receivables on a quarterly basis:

	Credit Quality Indicator	Grade	Year Ended December 31, 2018 $	Year Ended December 31, 2017 $
Direct financing leases	Payment activity	Performing	4,793	17,207

4. Segment Reporting

The Partnership is engaged in the international marine transportation of crude oil, the offshore processing and storage of crude oil, long-distance ocean towage and offshore installation services, and maintenance and safety services through the operation of its shuttle and conventional tankers, FSO units, FPSO units, towage and offshore installation vessels and UMS. The Partnership's revenues are earned in international markets.

The Partnership has six reportable segments: its FPSO segment; its shuttle tanker segment; its FSO segment; its UMS segment; its towage and offshore installation vessels (or towage) segment; and its conventional tanker segment. The Partnership's FPSO segment consists of its FPSO units to service its FPSO contracts. The Partnership's shuttle tanker segment consists of shuttle tankers operating primarily on fixed-rate contracts of affreightment, time-charter contracts or bareboat charter contracts. The Partnership's FSO segment consists of its FSO units subject to fixed-rate, time-charter contracts or bareboat charter contracts. The Partnership's UMS segment consists of one unit currently in lay-up. The Partnership's towage and offshore installation vessels segment consists of long-distance towage and offshore installation vessels which operate on time-charter or voyage charter contracts. The Partnership's conventional tanker segment consists of two in-chartered conventional tankers, which are currently operating in the spot conventional tanker market. Segment results are evaluated based on income from vessel operations. The accounting policies applied to the reportable segments are the same as those used in the preparation of the Partnership's consolidated financial statements.

The following table presents revenues and percentage of consolidated revenues for customers that accounted for more than 10% of the Partnership's consolidated revenues during the periods presented.

(U.S. Dollars in millions)	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Royal Dutch Shell Plc [(1)(2)]	$327.6 or 23%	$338.2 or 31%	$349.0 or 30%
Petroleo Brasileiro S.A.[(1)]	$254.8 or 18%	$190.7 or 17%	$222.0 or 19%
Equinor ASA (formerly Statoil ASA) [(3)]	$182.1 or 13%	$114.5 or 10%	— [(4)]
Premier Oil [(5)(6)]	— [(4)]	$113.5 or 10%	$113.5 or 10%

(1) Shuttle tanker and FPSO segments.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

(2) In February 2016, Royal Dutch Shell Plc acquired BG Group Plc; therefore the amount in the table for 2016 includes revenues from both Royal Dutch Shell Plc and BG Group Plc.
(3) Shuttle tanker segment and FSO segment.
(4) Percentage of consolidated revenue was less than 10%.
(5) In April 2016, Premier Oil acquired E.ON Ruhgras UK GP Limited's (or E.ON) UK North Sea assets where the Voyageur Spirit FPSO unit operates. Revenues up to April 2016 are attributable to E.ON.
(6) FPSO segment.

The following tables include results for the Partnership's FPSO unit segment; shuttle tanker segment; FSO unit segment; UMS segment; towage and offshore installation vessels segment; and conventional tanker segment for the periods presented in these consolidated financial statements.

Year ended December 31, 2018	FPSO Segment	Shuttle Tanker Segment	FSO Segment	UMS Segment	Towage Segment	Conventional Tanker Segment	Eliminations[3]	Total
Revenues[1]	533,186	636,413	136,557	36,536	53,327	21,325	(920)	1,416,424
Voyage expenses	—	(109,796)	(769)	(47)	(28,925)	(12,453)	182	(151,808)
Vessel operating expenses	(214,623)	(149,226)	(42,913)	(3,679)	(27,346)	—	116	(437,671)
Time-charter hire expenses	—	(36,421)	—	—	—	(16,195)	—	(52,616)
Depreciation and amortization	(145,451)	(155,932)	(44,077)	(6,611)	(20,323)	—	104	(372,290)
General and administrative[2]	(34,052)	(21,763)	(2,174)	(3,547)	(3,531)	(360)	—	(65,427)
(Write-down) and gain on sale of vessels	(180,200)	(43,155)	—	—	—	—	—	(223,355)
Restructuring charge	(1,520)	—	—	—	—	—	—	(1,520)
(Loss) income from vessel operations	(42,660)	120,120	46,624	22,652	(26,798)	(7,683)	(518)	111,737
Equity income	39,458	—	—	—	—	—	—	39,458
Investment in joint ventures	212,202	—	—	—	—	—	—	212,202
Expenditures for vessels and equipment, including advances on newbuilding contracts and conversion costs	54,371	147,540	6,987	—	24,838	—	—	233,736
Expenditures for dry docking	—	22,135	—	—	1,467	—	—	23,602

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

Year ended December 31, 2017	FPSO Segment	Shuttle Tanker Segment	FSO Segment	UMS Segment	Towage Segment	Conventional Tanker Segment	Eliminations(1)	Total
Revenues	458,388	536,852	66,901	4,236	38,771	14,022	(8,886)	1,110,284
Voyage expenses	—	(80,964)	(1,172)	(1,152)	(17,727)	(359)	1,930	(99,444)
Vessel operating (expenses) recoveries	(149,153)	(129,517)	(25,241)	(33,656)	(21,074)	10	5,067	(353,564)
Time-charter hire expenses	—	(62,899)	—	—	(925)	(16,491)	—	(80,315)
Depreciation and amortization	(143,559)	(125,648)	(19,406)	(6,566)	(15,578)	—	782	(309,975)
General and administrative(2)	(33,046)	(17,425)	(1,864)	(5,068)	(4,486)	(360)	—	(62,249)
(Write-down) and gain (loss) on sale of vessels	(265,229)	(51,741)	(1,108)	—	—	—	—	(318,078)
Restructuring charge	(450)	(210)	—	(2,004)	—	—	—	(2,664)
(Loss) income from vessel operations	(133,049)	68,448	18,110	(44,210)	(21,019)	(3,178)	(1,107)	(116,005)
Equity income	14,442	—	—	—	—	—	—	14,442
Investment in joint ventures	169,875	—	—	—	—	—	—	169,875
Expenditures for vessels and equipment, including advances on newbuilding contracts and conversion costs	193,817	216,157	88,039	3,931	31,316	—	—	533,260
Expenditures for dry docking	—	16,323	199	—	661	—	—	17,183

Year ended December 31, 2016	FPSO Segment	Shuttle Tanker Segment	FSO Segment	UMS Segment	Towage Segment	Conventional Tanker Segment	Eliminations	Total
Revenues	495,223	509,596	54,440	34,433	37,952	20,746	—	1,152,390
Voyage expenses	—	(62,846)	(1,517)	—	(15,024)	(1,363)	—	(80,750)
Vessel operating expenses	(165,346)	(123,950)	(23,167)	(32,888)	(17,524)	(1,566)	—	(364,441)
Time-charter hire expenses	—	(62,511)	—	—	—	(12,974)	—	(75,485)
Depreciation and amortization	(149,198)	(122,822)	(9,311)	(6,660)	(12,020)	—	—	(300,011)
General and administrative(2)	(35,971)	(10,160)	(836)	(5,495)	(3,307)	(353)	—	(56,122)
Gain on sale and (write down) of vessels	—	4,554	(983)	(43,650)	—	—	—	(40,079)
Restructuring charge	(4,444)	(205)	—	—	—	—	—	(4,649)
Income (loss) from vessel operations	140,264	131,656	18,626	(54,260)	(9,923)	4,490	—	230,853
Equity income	17,933	—	—	—	—	—	—	17,933
Investment in joint ventures	141,819	—	—	—	—	—	—	141,819
Expenditures for vessels and equipment, including advances on newbuilding contracts and conversion costs	66,234	40,584	101,347	9,742	76,674	—	—	294,581
Expenditures for dry docking	—	19,105	5,139	—	799	—	—	25,043

(1) Includes revenues of $55.0 million and $36.5 million in the shuttle tanker and UMS segments, respectively, during the year ended December 31, 2018 related to a settlement agreement with Petrobras and Petroleo Netherlands B.V. - PNBV S.A. (or Petrobras) in relation to the previously-terminated charter contracts of the HiLoad DP unit and

Arendal Spirit UMS (see note 5).

(2) Includes direct general and administrative expenses and indirect general and administrative expenses (allocated to each segment based on estimated use of corporate resources).

(3) Includes revenue and expenses earned and incurred between segments of the Partnership, during the years ended December 31, 2018 and December 31, 2017.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

A reconciliation of total segment assets to total assets presented in the accompanying consolidated balance sheets is as follows:

	December 31, 2018	December 31, 2017
	$	$
FPSO segment	2,279,277	2,506,660
Shuttle tanker segment	1,684,887	1,765,664
FSO segment	463,647	516,567
UMS segment	220,509	190,440
Towage segment	419,000	398,610
Conventional tanker segment	4,259	3,360
Unallocated:		
Cash and cash equivalents and restricted cash	233,580	250,294
Other assets	6,893	6,200
Consolidated total assets	5,312,052	5,637,795

5. Revenue

The Partnership’s primary source of revenues is chartering its vessels and offshore units to its customers. The Partnership utilizes five primary forms of contracts, consisting of FPSO contracts, CoAs, time-charter contracts, bareboat charter contracts and voyage charter contracts. During the year ended December 31, 2018, the Partnership also generated revenues from the operation of VOC systems on 13 of the Partnership’s shuttle tankers, and the management of three FPSO units, one FSO unit and two shuttle tankers on behalf of related parties who are the disponent owners or charterers of these assets.

FPSO Contracts
Pursuant to an FPSO contract, the Partnership charters an FPSO unit to a customer for a fixed period of time, generally more than one year. The performance obligations within an FPSO contract, which include the lease of the FPSO unit to the charterer as well as the operation of the FPSO unit, are satisfied as services are rendered over the duration of such contract, as measured using the time that has elapsed from commencement of performance. Fees relating to the lease and operation of the FPSO (or hire) are typically invoiced monthly in arrears, based on a fixed daily hire amount. In certain FPSO contracts, the Partnership is entitled to a lump sum amount due upon commencement of the contract and may also be entitled to termination fees if the contract is canceled early. While the fixed daily hire amount may be the same over the term of the FPSO contract, in certain cases, the daily hire amount declines over the duration of the FPSO contract. As a result of the Partnership accounting for compensation from such charters on a straight-line basis over the duration of the charter, FPSO contracts where revenues are recognized before the Partnership is entitled to such amounts under the FPSO contracts will result in the Partnership recognizing a contract asset and FPSO contracts where revenues are recognized after the Partnership is entitled to such amounts under the FPSO contracts will result in the Partnership recognizing a contract liability. Some FPSO contracts include variable consideration components in the form of expense adjustments or reimbursements, incentive compensation and penalties. For example, some FPSO contracts contain provisions that allow the Partnership to be compensated for increases in the Partnership's costs to operate the unit during the term of the contract. Such provisions may be in the form of annual hire rate adjustments for changes in inflation indices or foreign currency rates, or in the form of cost reimbursements for vessel operating expenditures incurred. The Partnership may also earn additional compensation from periodic production tariffs, which are based on the volume of oil produced, the price of oil, as well as other monthly or annual operational performance measures. During periods in which production on the FPSO unit is interrupted, penalties may be imposed. Variable consideration under the Partnership’s contracts is typically recognized

as incurred as either such revenues are allocated and accounted for under lease accounting requirements or alternatively such consideration is allocated to the distinct period in which such variable consideration was earned. The Partnership does not engage in any specific tactics to minimize residual value risk. Given the uncertainty involved in oil field production estimates and the resulting impact on oil field life, FPSO contracts typically will include extension options or options to terminate early.

Contracts of Affreightment

Voyages performed pursuant to a CoA for the Partnership's shuttle tankers are priced based on the pre-agreed terms in the CoA. The performance obligations within a voyage performed pursuant to a CoA, which will typically include the lease of the vessel to the charterer as well as the operation of the vessel, are satisfied as services are rendered over the duration of the voyage, as measured using the time that has elapsed from commencement of performance. In addition, any expenses that are unique to a particular voyage, including any bunker fuel expenses, port fees, cargo loading and unloading expenses, canal tolls, agency fees and commissions, are the responsibility of the vessel owner. Consideration for such voyages consists of a fixed daily hire rate for the duration of the voyage, the reimbursement of costs incurred from fuel consumed during the voyage, as well as a fixed lump sum intended to compensate for time necessary for the vessel to return to the field following completion of the voyage. While such consideration is generally fixed, certain sources of variability exist, including variability in the duration of the voyage and the actual quantity of fuel consumed during the voyage. Payment for the voyage is not due until the voyage is completed. The duration of a single voyage will typically be less than two weeks. The Partnership does not engage in any specific tactics to minimize residual value risk due to the short-term nature of the contracts.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

Time Charter Contracts

Pursuant to a time charter contract, the Partnership charters a vessel or FSO unit to a customer for a fixed period of time, generally one year or more. The performance obligations within a time-charter contract, which will include the lease of the vessel to the charterer as well as the operation of the vessel, are satisfied as services are rendered over the duration of such contract, as measured using the time that has elapsed from commencement of performance. In addition, any expenses that are unique to a particular voyage, including any bunker fuel expenses, port fees, cargo loading and unloading expenses, canal tolls, agency fees and commissions, are the responsibility of the customer, as long as the vessel is not off-hire. Hire is typically invoiced monthly in advance for time-charter contracts, based on a fixed daily hire amount. In certain long-term time-charters, the fixed daily hire amount will increase on an annual basis by a fixed amount to offset expected increases in operating costs. As a result of the Partnership accounting for compensation from such charters on a straight-line basis over the duration of the charter, such fixed increases in rate will result in revenues being accrued in the first half of the charter and such amount drawn down in the last half of the charter. Some time charters include variable consideration components in the form of expense adjustments or reimbursements, incentive compensation and penalties. For example, certain time charters contain provisions that allow the Partnership to be compensated for increases in the Partnership's costs during the term of the charter. Such provisions may be in the form of annual hire rate adjustments for changes in inflation indices or in the form of cost reimbursements for vessel operating expenditures or drydocking expenditures. During periods in which the vessels are off-hire or minimum speed and performance metrics are not met, penalties may be imposed. Variable consideration under the Partnership’s contracts is typically recognized as incurred as either such revenues are allocated and accounted for under lease accounting requirements or alternatively such consideration is allocated to the distinct period in which such variable consideration was earned. The Partnership does not engage in any specific tactics to minimize residual value risk.

The time charters for the three shuttle tankers servicing the East Coast Canada project can be canceled upon two years' notice. The time charters for four shuttle tankers in Brazil can be extended by up to ten years, at the election of the charterer. The time charters for the vessels servicing the Equinor North Sea requirements under the terms of a master agreement are one year in length and may be renewed for subsequent one-year periods. The number of vessels required under the terms of the master agreement may be adjusted annually based on the requirements of the fields serviced. The time charter contracts for three FSO units can be extended for periods between five and 12 years or terminated early.

Bareboat Charter Contracts

Pursuant to a bareboat charter contract, the Partnership charters a vessel or FSO unit to a customer for a fixed period of time, generally one year or more, at rates that are generally fixed. However, the customer is responsible for operation and maintenance of the vessel with their own crew as well as any expenses that are unique to a particular voyage, including any bunker fuel expenses, port fees, cargo loading and unloading expenses, canal tolls, agency fees and commissions. If the vessel goes off-hire due to a mechanical issue or any other reason, the monthly hire received by the vessel owner is normally not impacted by such events. The performance obligations within a bareboat charter, which will include the lease of the vessel to the charterer, are satisfied as over the duration of such contract, as measured using the time that has elapsed from commencement of the lease. Hire is typically invoiced monthly in advance for bareboat charters, based on a fixed daily hire amount.

Voyage Charters

Voyage charters are charters for a specific voyage. Voyage charters for the Partnership’s shuttle tankers, conventional tankers and towage and offshore installation vessels are priced on a current or “spot” market rate. The performance obligations within a voyage charter contract, which will typically include the lease of the vessel to the charterer as well as the operation of the vessel, are satisfied as services are rendered over the duration of the voyage, as measured using the time that has elapsed from commencement of performance. In addition, expenses that are unique to a particular voyage, including any bunker fuel expenses, port fees, cargo loading and unloading expenses, canal tolls, agency fees and commissions, are the responsibility of the vessel owner. The Partnership’s voyage charters for shuttle tankers and conventional tankers will normally contain a lease, whereas for towage and offshore installation vessels such contracts will not normally contain a lease. Such determination involves judgment about the decision-making rights the charterer has within the contract. Consideration for such contracts is generally fixed; however, certain sources of variability exist. Delays caused by the charterer result in additional consideration. Payment for the voyage is not due until the voyage is completed. The duration of a single voyage will typically be less than three months. The Partnership does not engage in any specific tactics to minimize residual value risk due to the short-term nature of the contracts.

Management Fees and Other

During the year ended December 31, 2018, the Partnership also generated revenues from the operation of VOC systems on 13 of the Partnership's shuttle tankers, and the management of three FPSO units, one FSO unit and two shuttle tankers on behalf of related parties who are the disponent owners or charterers of these assets. Such services include the arrangement of third-party goods and services for the asset's disponent owner or charterer. The performance obligations within these contracts will typically consist of crewing, technical management, insurance and, potentially, commercial management. The performance obligations are satisfied concurrently and consecutively rendered over the duration of the management contract, as measured using the time that has elapsed from commencement of performance. Consideration for such contracts will generally consist of a fixed monthly management fee, plus the reimbursement of crewing costs for vessels being managed and all operational costs for the VOC systems. Management fees are typically invoiced monthly.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

Revenue Table
The following tables contain the Partnership's revenue for the years ended December 31, 2018, 2017 and 2016, by contract type and by segment:

Year ended December 31, 2018	FPSO Segment	Shuttle Tanker Segment	FSO Segment	UMS Segment	Towage Segment	Conventional Tanker Segment	Eliminations[1]	Total
FPSO contracts	481,700	—	—	—	—	—	—	481,700
Contracts of affreightment	—	198,448	—	—	—	—	—	198,448
Time charters	—	294,112	116,125	—	—	—	—	410,237
Bareboat charters	—	44,759	17,383	—	—	—	—	62,142
Voyage charters	—	28,027	—	—	53,327	21,325	(920)	101,759
Management fees and other [2]	51,486	71,067	3,049	36,536	—	—	—	162,138
	533,186	636,413	136,557	36,536	53,327	21,325	(920)	1,416,424

Year ended December 31, 2017	FPSO Segment	Shuttle Tanker Segment	FSO Segment	UMS Segment	Towage Segment	Conventional Tanker Segment	Eliminations[1]	Total
FPSO contracts	458,388	—	—	—	—	—	—	458,388
Contracts of affreightment	—	170,703	—	—	—	—	—	170,703
Time charters	—	284,281	47,605	4,236	—	9,132	—	345,254
Bareboat charters	—	69,568	19,296	—	—	—	—	88,864
Voyage charters	—	12,300	—	—	38,771	4,890	(8,886)	47,075
	458,388	536,852	66,901	4,236	38,771	14,022	(8,886)	1,110,284

Year ended December 31, 2016	FPSO Segment	Shuttle Tanker Segment	FSO Segment	UMS Segment	Towage Segment	Conventional Tanker Segment	Eliminations	Total
FPSO contracts	495,223	—	—	—	—	—	—	495,223
Contracts of affreightment	—	148,367	—	—	—	—	—	148,367
Time charters	—	251,217	38,600	34,433	—	12,271	—	336,521
Bareboat charters	—	91,994	15,840	—	—		—	107,834
Voyage charters	—	18,018	—	—	37,952	8,475	—	64,445
	495,223	509,596	54,440	34,433	37,952	20,746	—	1,152,390

(1) Includes revenues earned between segments of the Partnership, during the years ended December 31, 2018 and December 31, 2017.

(2) Includes revenues of $55.0 million and $36.5 million in the shuttle tanker and UMS segments, respectively, related to a settlement agreement with Petrobras in relation to the previously-terminated charter contracts of the HiLoad DP unit and Arendal Spirit UMS. As part of the settlement agreement, Petrobras has agreed to pay a total amount of $96.0 million to the Partnership, which includes $55.0 million that was paid November 2018, and amounts of $22.0 million payable in late-2020 and $19.0 million payable in late-2021, which are available to be reduced by 40% of the revenues paid prior to the end of 2021 by Petrobras under any new contracts entered into subsequent to October 25, 2018 relating specifically to the Arendal Spirit UMS and the Cidade de Rio das Ostras and Piranema Spirit FPSO units.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

The following table contains the Partnership's revenue from contracts that do not contain a lease element and the non-lease element of time-charters accounted for as direct financing leases for the years ended December 31, 2018, 2017 and 2016:

	Year ended December 31,		
	2018	2017	2016
	$	$	$
Non-lease revenue - related to sales type or direct financing leases	4,547	5,813	6,203
Voyage charters - towage	53,327	38,771	37,952
Management fees and other	162,138	—	—
Total	220,012	44,584	44,155

Contract Assets and Liabilities

Certain customer contracts that the Partnership enters into will result in situations where the customer will pay consideration for performance to be provided in the following month or months. These receipts are a contract liability and are presented as deferred revenue until performance is provided. In other cases, the Partnership will provide performance in the month or months prior to it being entitled to invoice for such performance. This results in such receipts being reflected as a contract asset that is presented within other current assets. In addition to these short-term timing differences between the timing of revenue recognition and when the entity's right to consideration in exchange for goods or services is unconditional, the Partnership has long-term charter arrangements whereby it has received payments that are larger in the early periods of the arrangements and long-term charter arrangements whereby it will receive payments that are larger in the latter periods of the arrangements. The following table presents the contract assets and contract liabilities on the Partnership's consolidated balance sheets associated with these long-term charter arrangements from contracts with customers.

	December 31, 2018	January 1, 2018
	$	$
Contract Assets		
Current	7,926	3,866
Non-Current	62,295	54,919
	70,221	58,785
Contract Liabilities		
Current	55,750	69,668
Non-Current	145,852	176,755
	201,602	246,423

During the year ended December 31, 2018 the Partnership recognized revenue of $38.4 million, that was included in the contract liability on January 1, 2018.

Contract Costs

In certain cases, the Partnership incurs pre-operational costs that relate directly to a specific customer contract, that generate or enhance resources of the Partnership that will be used in satisfying performance obligations in the future, whereby such costs are expected to be recovered via the customer contract. These costs include costs incurred to mobilize an offshore asset to an oil field, pre-operational costs incurred to prepare for commencement of operations of an offshore asset or costs incurred to reposition a vessel to a location where a charterer will take delivery of the vessel. In certain cases, the Partnership will need to make judgments about whether costs relate directly to a specific customer contract and whether costs were factored into the pricing of a customer contract and thus expected to be recovered. Such deferred costs are amortized into vessel operating expenses over the duration of the customer contract. Amortization of such costs for the Partnership for the year ended December 31, 2018, 2017 and 2016 was $19.7

million, $24.1 million and $18.9 million, respectively.
The balances of assets recognized from the costs to fulfill a contract with a customer classified as other assets, split between current and non-current portions, on the Partnership's balance sheet, by main category, excluding balances in the Partnership’s equity accounted joint ventures, are as follows:

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

	Year ended December 31,		
	2018	2017	2016
	$	$	$
Pre-operational costs	24,031	4,522	2,855
Offshore asset mobilization costs	51,302	57,818	65,360
Vessel repositioning costs	15,188	—	—
	90,521	62,340	68,215

6. Goodwill and In-Process Revenue Contracts

a) Goodwill

The carrying amount of goodwill for the shuttle tanker segment was $127.1 million as at December 31, 2018 and 2017. In 2018, 2017 and 2016, the Partnership conducted its annual goodwill impairment review of its shuttle tanker segment and concluded that no impairment had occurred.

The carrying amount of goodwill for the towage and offshore installation vessels segment was $2.0 million as at December 31, 2018 and 2017. In 2018, 2017 and 2016, the Partnership conducted its annual goodwill impairment review of its towage and offshore installation vessels segment and concluded that no impairment had occurred.

b) In-Process Revenue Contracts

As part of the Partnership's acquisition of the Piranema Spirit FPSO unit on November 30, 2011, the Partnership assumed an FPSO contract with terms that were less favorable than the then prevailing market terms. As at December 31, 2018, the Partnership had a liability based on the estimated fair value of the contract. The Partnership is amortizing this liability over the estimated remaining term of the contract on a weighted basis based on the projected revenue to be earned under the contract.

Amortization of in-process revenue contracts for the year ended December 31, 2018 was $35.2 million (2017 - $12.7 million, 2016 - $12.8 million), which is included in revenues on the consolidated statements of (loss) income. Amortization subsequent to December 31, 2018 is expected to be $15.1 million (2019).

7. Accrued Liabilities

	December 31, 2018	December 31, 2017
	$	$
Interest including interest rate swaps	44,887	26,111
Payroll and benefits	34,828	10,378
Voyage and vessel expenses	25,475	38,921
Audit, legal, contingency and other general expenses	21,626	101,130
Income and other tax payable	3,080	11,147
	129,896	187,687

8. Long-Term Debt

	December 31, 2018	December 31, 2017
	$	$
U.S. Dollar-denominated Revolving Credit Facilities due through 2022	523,125	629,667
U.S. Dollar-denominated Term Loans due through 2030	1,388,107	1,623,440

U.S. Dollar-denominated Term Loan due through 2021	55,018	85,574
U.S. Dollar Bonds due through 2023	1,024,816	550,000
U.S. Dollar Non-Public Bonds due through 2024	141,158	162,659
Norwegian Krone Bonds due through 2019	9,953	121,889
Total principal	3,142,177	3,173,229
Less debt issuance costs and other	(44,435)	(49,501)
Total debt	3,097,742	3,123,728
Less current portion	(554,336)	(589,767)
Long-term portion	2,543,406	2,533,961

As at December 31, 2018, the Partnership had two revolving credit facilities (December 31, 2017 - three), which, as at such date, provided for total borrowings of up to $523.1 million (December 31, 2017 - $629.7 million) and were fully drawn (December 31, 2017 - fully drawn). The total amount available under the revolving credit facilities reduces by $148.1 million (2019), $100.0 million (2020), $100.0 million (2021) and $175.0 million (2022). One revolving credit facility is guaranteed by the Partnership for all outstanding amounts and contains covenants that require the Partnership to maintain a minimum liquidity (cash, cash equivalents and undrawn committed revolving credit lines with at least six months to maturity) in an amount equal to the greater of $75.0 million and 5.0% of the Partnership’s total consolidated debt. The other revolving credit facility is guaranteed by subsidiaries of the Partnership, and contains covenants that require Teekay Shuttle Tankers L.L.C. (a wholly-owned subsidiary of the Partnership which was formed during 2017 to hold the Partnership’s shuttle tanker fleet) to maintain a minimum liquidity (cash, cash equivalents and undrawn committed revolving credit lines with at least six months to maturity) in an amount equal to the greater of $35.0 million and 5.0% of Teekay Shuttle Tankers L.L.C.'s total consolidated debt, a minimum ratio of 12 months' historical EBITDA relative to total interest expense and installments of 1.20 times and a net debt to total capitalization ratio no greater than 75.0%. The revolving credit facilities are collateralized by first-priority mortgages granted on 19 of the Partnership’s vessels, together with other related security.

As at December 31, 2018, the Partnership had term loans outstanding secured by three shuttle tankers, two FSO units, three FPSO units, ten towage and offshore installation vessels, four shuttle tanker newbuildings, and for the Arendal Spirit UMS, which totaled $1.4 billion in the aggregate. The term loans reduce over time with quarterly or semi-annual payments and have varying maturities through 2030. As at December 31, 2018, the Partnership or a subsidiary of the Partnership had guaranteed all of these term loans.

As at December 31, 2018, two of the Partnership’s 50%-owned subsidiaries had one outstanding term loan (December 31, 2017 - three), which totaled $55.0 million (December 31, 2017 - $85.6 million). The term loan reduces over time with quarterly payments and matures in 2021. The term loan is collateralized by first-priority mortgages on the two shuttle tankers to which the loan relates, together with other related security. As at December 31, 2018, a subsidiary of the Partnership guaranteed $27.5 million of the term loan, which represents its 50% share of the outstanding term loan, and the other owner had guaranteed the remaining $27.5 million of the term loan.

Interest payments on the revolving credit facilities and the term loans are based on LIBOR plus margins, except for $79.9 million of one tranche of the term loan for the newbuilding towage and offshore installation vessels, which is fixed at 2.93%. At December 31, 2018, the margins ranged between 0.90% and 4.30%, (December 31, 2017, 0.90% and 3.75%). The weighted-average interest rate on the Partnership’s U.S. Dollar variable rate long-term debt as at December 31, 2018 was 5.1% (December 31, 2017 – 4.1%). This rate does not include the effect of the Partnership’s interest rate swaps (see note 12) or fixed rate facilities.

In July 2018, the Partnership issued, in a U.S. private placement, $700.0 million of five-year senior unsecured bonds that mature in July 2023. The interest payments on the bonds are fixed at a rate of 8.50%. The bonds contain certain incurrence-based covenants. As at December 31, 2018, the carrying amount of the bonds was $700.0 million. Brookfield Business Partners L.P. and its institutional investors (or Brookfield) purchased $500.0 million of these bonds and as at December 31, 2018 held $475.0 million of these bonds (see note 11i).

In August 2017, the Partnership's wholly-owned subsidiary Teekay Shuttle Tankers L.L.C. issued $250.0 million in senior unsecured bonds in the Norwegian bond market that mature in August 2022. These bonds are listed on the Oslo Stock Exchange. As at December 31, 2018, the carrying amount of the bonds was $250.0 million. The interest payments on the bonds are fixed at a rate of 7.125%.

In May 2014, the Partnership issued $300.0 million in five-year senior unsecured bonds that mature in July 2019 in the U.S. bond market. In July 2018, the Partnership completed a tender offer for these bonds, in which an aggregate principal amount of $225.2 million was repurchased by the Partnership for an aggregate purchase price of $230.8 million. As at December 31, 2018, the carrying amount of the remaining bonds was $74.8 million. The bonds are listed on the New York Stock Exchange. The interest payments on the bonds are fixed at a rate of 6.00%.

In February 2015, the Partnership issued $30.0 million in senior bonds that mature in July 2024 in a U.S. private placement. The interest payments on the bonds are fixed at a rate of 4.27%. The bonds are collateralized by a first-priority mortgage on the Dampier Spirit FSO unit, together with other related security, and are guaranteed by subsidiaries of the Partnership. The Partnership makes semi-annual repayments on the bonds and as at December 31, 2018, the carrying amount of the bonds was $17.2 million.

In September 2013 and November 2013, the Partnership issued, in a U.S. private placement, a total of $174.2 million of ten-year senior bonds that mature in January 2024, to finance the Bossa Nova Spirit and Sertanejo Spirit shuttle tankers. The bonds accrue interest at a fixed combined rate of 4.96%. The bonds are collateralized by first-priority mortgages on the two vessels to which the bonds relate, together with other related security, and are guaranteed by subsidiaries of the Partnership. The Partnership makes semi-annual repayments on the bonds and as at December 31, 2018, the carrying amount of the bonds was $123.9 million.

As at December 31, 2018, the Partnership had Norwegian Krone (or NOK) 86 million (December 31, 2017 - NOK 1,000 million) outstanding in senior unsecured bonds that mature in January 2019 and that are listed on the Oslo Stock Exchange. In July 2018, the Partnership completed a tender offer for these bonds, in which an aggregate principal amount of NOK 914 million was repurchased by the Partnership for an aggregate purchase price of NOK 932.2 million ($113.8 million). As at December 31, 2018, the carrying amount of the remaining bonds was $10.0 million. The interest payments on the bonds are based on NIBOR plus a margin of 4.25%. The Partnership has entered into cross currency swaps to swap interest and principal payments into U.S. Dollars, with the interest payments fixed at a rate of 7.45%, and the transfer of the principal amount fixed at $15.4 million upon maturity in exchange for NOK 95 million (see note 12).

In connection with the repurchases of $225.2 million of five-year senior unsecured bonds and NOK 914 million of senior unsecured bonds, as well as the repayment of a promissory note (or the Brookfield Promissory Note) to Brookfield (see note 11(f)), the Partnership recognized losses on debt repurchases of $55.5 million during the year ended December 31, 2018. The losses on debt repurchases are comprised of

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

an acceleration of non-cash accretion expense of $31.5 million resulting from the difference between the $200.0 million settlement amount of the Brookfield Promissory Note at its par value and its carrying value of $168.5 million and an associated early termination fee of $12.0 million paid to Brookfield, as well as 2.0% - 2.5% premiums on the repurchases of the bonds and the write-off of capitalized loan costs.

The aggregate annual long-term debt principal repayments required to be made subsequent to December 31, 2018, are $556.4 million (2019), $349.0 million (2020), $303.0 million (2021), $596.3 million (2022), $974.8 million (2023), and $362.7 million (thereafter).

Certain of the Partnership’s revolving credit facilities, term loans and bonds contain covenants, debt-service coverage ratio (or DSCR) requirements and other restrictions typical of debt financing secured by vessels that restrict the ship-owning subsidiaries from, among other things: incurring or guaranteeing indebtedness; changing ownership or structure, including mergers, consolidations, liquidations and dissolutions; paying dividends or distributions if the Partnership is in default or does not meet minimum DSCR requirements; making capital expenditures in excess of specified levels; making certain negative pledges and granting certain liens; selling, transferring, assigning or conveying assets; making certain loans and investments; or entering into a new line of business. Obligations under the Partnership’s credit facilities are secured by certain vessels, and if the Partnership is unable to repay debt under the credit facilities, the lenders could seek to foreclose on those assets. The Partnership has one revolving credit facility and seven term loans that require the Partnership to maintain vessel values to drawn principal balance ratios of a minimum range of 100% to 125%. Such requirement is assessed either on a semi-annual or annual basis, with reference to vessel valuations compiled by one or more agreed upon third parties. Should the ratio drop below the required amount, the lender may request the Partnership to either prepay a portion of the loan in the amount of the shortfall or provide additional collateral in the amount of the shortfall, at the Partnership's option. As at December 31, 2018, these hull covenant ratios were estimated to range from 122% to 414% and the Partnership was in compliance with the minimum ratios required. The vessel values used in calculating these ratios are the appraised values provided by third parties where available, or prepared by the Partnership based on second-hand sale and purchase market data. Changes in the shuttle tanker, towage and offshore installation, UMS, or FPSO markets could negatively affect these ratios.

As at December 31, 2018, the Partnership was in compliance with all covenants related to the credit facilities and consolidated long-term debt.

9. Leases

Charters-out

The cost, accumulated depreciation and carrying amount of the Partnership's vessels with charter-out contracts accounted for as operating leases at December 31, 2018 were $4.3 billion, $1.1 billion and $3.2 billion, respectively (2017 - $4.4 billion, $1.0 billion and $3.4 billion, respectively). As at December 31, 2018, minimum scheduled future rentals under these then-in-place time charters and bareboat charters to be received by the Partnership, were approximately $3.5 billion, comprised of $763.0 million (2019), $661.6 million (2020), $576.4 million (2021), $537.4 million (2022), $277.4 million (2023) and $727.9 million (thereafter).

The minimum scheduled future revenues should not be construed to reflect total charter hire revenues for any of the years. Minimum scheduled future revenues do not include revenue generated from new contracts entered into after December 31, 2018, revenue from unexercised option periods of contracts that existed on December 31, 2018, or variable or contingent revenues. The amounts may vary given unscheduled future events such as vessel maintenance.

Direct Financing Lease

Leasing of certain VOC equipment is accounted for as a direct financing lease. As at December 31, 2018, the minimum lease payments receivable under the direct financing lease approximated $5.9 million (2017 - $7.6 million), including unearned income of $1.1 million (2017 - $1.9 million). As at December 31, 2018, future scheduled payments under the direct financing leases to be received by the Partnership, were approximately $5.9 million, comprised of $1.3 million (2019), $1.3 million (2020), $1.3 million (2021), $1.3 million (2022) and $0.6 million (2023).

Charters-in

As at December 31, 2018, minimum commitments owing by the Partnership under vessel operating leases by which the Partnership charters-in vessels were approximately $34.3 million (2019) and $2.2 million (2020). The Partnership recognizes the expense from these charters, which is included in time-charter hire expense, on a straight-line basis over the firm period of the charters.

10. Restructuring Charge

During the year ended December 31, 2018, the Partnership recognized a restructuring charge of $1.5 million, mainly relating to severance costs from crew reduction on the Petrojarl Varg FPSO unit, which is currently in lay-up. The Partnership incurred a total of $1.5 million of restructuring charges under this plan.

During the year ended December 31, 2017, the Partnership recognized a restructuring charge of $2.7 million, mainly relating to severance costs from the termination of the charter contract for the Arendal Spirit UMS and the resulting decommissioning of the unit. The Partnership incurred a total of $2.7 million of restructuring charges under this plan.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

During the year ended December 31, 2016, the Partnership recognized a restructuring charge of $4.6 million, mainly relating to the reorganization of the Partnership's FPSO business to create better alignment with the Partnership's offshore operations, resulting in a lower cost organization going forward. The Partnership incurred a total of $4.7 million of restructuring charges under this plan.

As of December 31, 2018 and December 31, 2017, restructuring liabilities of $1.5 million and $0.4 million, respectively, were recorded in accrued liabilities on the consolidated balance sheet.

11. Related Party Transactions and Balances

a) In May 2013, the Partnership entered into an agreement with Equinor ASA (or Equinor), on behalf of the field license partners, to provide an FSO unit for the Gina Krog oil and gas field located in the North Sea. The contract has been serviced since early-October 2017 by a new FSO unit that was converted from the Randgrid shuttle tanker, which conversion commenced during the second quarter of 2015 (see note 14a). The Partnership received project management and engineering services from certain subsidiaries of Teekay Corporation relating to this FSO unit conversion. The costs for these services were capitalized and included as part of vessels and equipment. Cumulative project management and engineering costs paid to Teekay Corporation subsidiaries up to completion of the project in 2017 were $18.0 million.

b) In December 2014, the Partnership entered into an agreement with a consortium led by Queiroz Galvão Exploração e Produção SA (or QGEP) to provide an FPSO unit for the Atlanta field located in the Santos Basin offshore Brazil. In connection with the contract with QGEP, the Partnership acquired the Petrojarl I FPSO unit from Teekay Corporation for a purchase price of $57 million (see note 14c). The Partnership has received project management and engineering services from certain subsidiaries of Teekay Corporation relating to this FPSO unit upgrade. The costs for these services have been capitalized and included as part of vessels and equipment. Cumulative project management and engineering costs paid to Teekay Corporation subsidiaries up to completion of the project in 2018 were $4.5 million.

c) In June 2015, the Partnership entered into 15-year contracts, plus extension options, with a group of oil companies to provide shuttle tanker services for oil production on the East Coast of Canada. The Partnership entered into contracts to have three Suezmax DP2 shuttle tanker newbuildings constructed. These vessels replaced the existing vessels servicing the East Coast of Canada. Two of the three newbuildings delivered in October and November 2017, respectively and the third vessel delivered in March 2018. The Partnership has received project management and engineering services from certain subsidiaries of Teekay Corporation relating to the construction of these shuttle tankers. The costs for these services have been capitalized and included as part of vessels and equipment. Project management and engineering costs paid to Teekay Corporation subsidiaries up to delivery of the final vessel in 2018 were $4.1 million.

d) During the year ended December 31, 2018, three shuttle tankers and three FSO units (December 31, 2017 - two shuttle tankers and three FSO units, December 31, 2016 - one conventional tanker, two shuttle tankers and three FSO units) of the Partnership were employed on long-term time-charter-out or bareboat contracts with subsidiaries of Teekay Corporation.

e) Effective July 1, 2016, the Partnership issued a $200.0 million promissory note to a subsidiary of Teekay Corporation (or the 2016 Teekay Corporation Promissory Note) to re-finance existing promissory notes issued to Teekay Corporation. The 2016 Teekay Corporation Promissory Note bore interest at an annual rate of 10.00% on the outstanding principal balance, which was payable quarterly, and of which (a) 5.00% was payable in cash and (b) 5.00% was payable in common units of the Partnership, or in cash, at the election of Teekay Corporation. If the

Partnership paid cash for the second 5.00% of interest, the Partnership was required to raise at least an equal amount of cash proceeds from the issuance of common units in advance of or within six months following the applicable interest payment date. The outstanding principal balance of the 2016 Teekay Corporation Promissory Note, together with accrued interest, was payable in full on January 1, 2019. On September 25, 2017, the Partnership, Teekay Corporation and Brookfield entered into an agreement to amend and restate this promissory note (see note 11f). During the year ended December 31, 2017, the Partnership incurred $14.6 million of interest expense on the 2016 Teekay Corporation Promissory Note (December 31, 2016 - $10.0 million), of which $9.6 million was paid in cash (December 31, 2016 - $7.5 million) and the remainder was settled through the issuance of 1.7 million common units of the Partnership (December 31, 2016 - 0.5 million common units) under the terms of the 2016 Teekay Corporation Promissory Note.

f) Effective September 25, 2017, the Partnership, Teekay Corporation and Brookfield amended and restated the 2016 Teekay Corporation Promissory Note to create the Brookfield Promissory Note, concurrently with Brookfield’s acquisition of the 2016 Teekay Corporation Promissory Note from a subsidiary of Teekay Corporation. The Brookfield Promissory Note of $200.0 million bore interest at an annual rate of 10.00% on the outstanding principal balance, which was payable quarterly. The outstanding principal balance of the Brookfield Promissory Note, together with accrued interest, was payable in full on January 1, 2022. The Brookfield Promissory Note was recorded at its relative fair value of $163.6 million based on the allocation of net proceeds invested by Brookfield, as at September 25, 2017 (see note 16). On July 2, 2018, the Partnership repurchased the Brookfield Promissory Note (see note 11i). During the year ended December 31, 2018, the Partnership incurred $10.0 million (December 31, 2017 - $5.3 million) of interest expense under the terms of the Brookfield Promissory Note.

g) In June 2016, as part of various other financing initiatives, Teekay Corporation agreed to provide financial guarantees for the Partnership's liabilities associated with the long-term debt financing relating to the East Coast of Canada newbuilding shuttle tankers until their deliveries, and for certain of the Partnership's interest rate swaps and cross currency swaps until early-2019. The guarantees covered liabilities totaling up to a maximum amount of $495.0 million. Effective September 25, 2017, the Partnership secured the release, for fees to the applicable counterparties, of all of these financial guarantees provided by Teekay Corporation relating to the Partnership's interest rate swap, cross currency swap agreements and East Coast of Canada financing. During the year ended December 31, 2017, a guarantee fee of $5.8 million (December 31, 2016 - $3.7 million) was recognized in interest expense on the Partnership's consolidated statements

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

of (loss) income, which represents the estimated fee a third party would charge to provide such financial guarantees. The guarantee fee was accounted for as an equity contribution by Teekay Corporation in the Partnership's consolidated statement of changes in total equity, as Teekay Corporation had provided such financial guarantees at no cost to the Partnership.

h) On March 31, 2018, the Partnership entered into a credit agreement for an unsecured revolving credit facility provided by Teekay Corporation and Brookfield, which provides for borrowings of up to $125.0 million ($25.0 million by Teekay Corporation and $100.0 million by Brookfield) and as at December 31, 2018, the credit facility was fully drawn. The revolving credit facility matures on October 1, 2019. The interest payments on the revolving credit facility are based on LIBOR plus a margin of 5.00% per annum until March 31, 2019 and LIBOR plus a margin of 7.00% per annum for balances outstanding after March 31, 2019, with interest payable monthly. Any outstanding principal balances are due on the maturity date. The revolving credit facility contains covenants that require the Partnership to maintain a minimum liquidity (cash, cash equivalents and undrawn committed revolving credit lines with at least six months to maturity) in an amount equal to the greater of $75.0 million and 5.0% of the Partnership's total consolidated debt. As at December 31, 2018, the Partnership was in compliance with these covenants.

i) On July 2, 2018, the Partnership issued, in a U.S. private placement, a total of $700.0 million of five-year senior unsecured bonds that mature in July 2023. The interest payments on the bonds are fixed at a rate 8.50% (see note 8). Brookfield purchased $500.0 million of these bonds, which included an exchange of the Brookfield Promissory Note at its par value of $200.0 million and additionally, the Partnership paid an associated $12.0 million early termination fee to Brookfield. As at December 31, 2018, Brookfield held $475.0 million of these bonds, which is included in long-term debt on the Partnership's balance sheet. The loss on the exchange of the Brookfield Promissory Note is included in losses on debt repurchases on the Partnership's consolidated statements of (loss) income.

j) As a condition of Brookfield's acquisition of 60% of the common units of the Partnership in September 2017, on January 1, 2018, the Partnership acquired a 100% ownership interest in seven subsidiaries of Teekay Corporation for cash consideration of $1.4 million. These subsidiaries provide ship management, commercial, technical, strategic, business development and administrative services to the Partnership, primarily related to the Partnership's FPSO units, shuttle tankers and FSO units.

k) Until December 31, 2017, Teekay Corporation and its wholly-owned subsidiaries directly and indirectly provided to the Partnership a majority of its commercial, technical, crew training, strategic, business development and administrative service needs. As described in note 11j, the majority of these services was assumed by the Partnership through the acquisition, on January 1, 2018, of certain management companies from Teekay Corporation that provide the bulk of their services to the Partnership's assets. In addition, the Partnership reimburses the general partner for expenses incurred by the general partner that are necessary or appropriate for the conduct of the Partnership's business. As at December 31, 2018, Brookfield and Teekay Corporation owned 51% and 49%, respectively, of the general partner ownership interests. The Partnership's related party transactions recognized in the consolidated statements of (loss) income were as follows for the periods indicated:

	Year Ended December 31,		
	2018	2017	2016
	$	$	$
Revenues (1)	117,764	49,509	49,228
Vessel operating expenses (2)	(6,298)	(32,346)	(34,629)
General and administrative (3)	(18,162)	(31,340)	(29,944)
Interest expense (4)(5)(6)(7)(8)(9)(10)	(38,695)	(25,882)	(22,400)

Losses on debt repurchases [11]	(46,041)	—	—

(1) Includes revenue from time-charter-out or bareboat contracts with subsidiaries of Teekay Corporation, including management fees from ship management services provided by the Partnership to a subsidiary of Teekay Corporation. The year ended December 31, 2016 includes an early termination fee received by the Partnership from Teekay Corporation of $4.0 million.

(2) Includes ship management and crew training services provided by Teekay Corporation.

(3) Includes commercial, technical, strategic, business development and administrative management fees charged by Teekay Corporation and reimbursements to Teekay Corporation and the general partner for costs incurred on the Partnership’s behalf.

(4) Includes interest expense of $10.0 million for the year ended December 31, 2018 (December 31, 2017 and 2016 - $5.3 million and $nil, respectively), and accretion expense of $2.7 million for the year ended December 31, 2018 (December 31, 2017 and 2016 - $2.2 million and $nil, respectively), incurred on the Brookfield Promissory Note (see note 11f). The Brookfield Promissory Note was recorded at its relative fair value at its acquisition date of $163.6 million and is recorded net of debt issuance costs on the Partnership's consolidated balance sheet as at December 31, 2017. On July 2, 2018, the Partnership repurchased the Brookfield Promissory Note (see note 11i).

(5) Includes interest expense of $5.0 million for the year ended December 31, 2018 (December 31, 2017 and 2016 - $nil and $nil, respectively), incurred on the unsecured revolving credit facility provided by Teekay Corporation and Brookfield, which the Partnership entered into on March 31, 2018 (see note 11h).

(6) Includes interest expense of $21.0 million for the year ended December 31, 2018 (December 31, 2017 and 2016 - $nil and $nil, respectively), incurred on the portion of five-year senior unsecured bonds held by Brookfield (see note 11i).

(7) Includes interest expense of $14.6 million for the year ended December 31, 2017 (December 31, 2016 - $10.0 million), incurred on the 2016 Teekay Corporation Promissory Note (see note 11e).

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

(8) Includes a guarantee fee related to the final bullet payment of the Piranema Spirit FPSO unit debt facility, which was repaid in March 2017, and a guarantee fee related to the Partnership's liabilities associated with the long-term debt financing relating to the East Coast of Canada shuttle tanker newbuildings and certain of the Partnership's interest rate swaps and cross currency swaps until September 25, 2017 (see notes 11g and 12).

(9) Includes interest expense of $5.0 million for the year ended December 31, 2016, incurred on a $100.0 million six-month loan made by Teekay Corporation to the Partnership on January 1, 2016, which bore interest at an annual rate of 10.00% on the outstanding principal balance. The loan was refinanced on July 1, 2016 under the 2016 Teekay Corporation Promissory Note.

(10) Includes interest expense of $3.2 million for the year ended December 31, 2016, incurred on a $100 million convertible promissory note issued to Teekay Corporation, which bore interest at an annual rate of 6.50% on the outstanding principal balance. The convertible promissory note was refinanced on July 1, 2016 under the 2016 Teekay Corporation Promissory Note.

(11) Includes the loss on the Partnership's prepayment of the Brookfield Promissory Note, which includes the acceleration of non-cash accretion expense of $31.5 million resulting from the difference between the $200.0 million settlement amount at its par value and its carrying value of $168.5 million, an associated early termination fee of $12.0 million paid to Brookfield and the write-off of capitalized loan costs (see note 11i).

l) At December 31, 2018, the carrying value of amounts due from affiliates totaled $59.8 million (December 31, 2017 - $37.4 million) and the carrying value of amounts due to affiliates totaled $183.8 million (December 31, 2017 - $271.5 million). Amounts due to and from affiliates, other than the Brookfield Promissory Note, the unsecured revolving credit facility provided by Teekay Corporation and Brookfield, and one term loan provided to a subsidiary of Teekay Corporation are non-interest bearing and unsecured, and all due to and from affiliates balances classified as current are expected to be settled within the next fiscal year in the normal course of operations or from financings.

12. Derivative Instruments

The Partnership uses derivative instruments to manage certain risks in accordance with its overall risk management policies.

Foreign Exchange Risk

The Partnership economically hedges portions of its forecasted expenditures denominated in foreign currencies with foreign currency forward contracts. The Partnership has not designated, for accounting purposes, any of the foreign currency forward contracts held during the years ended December 31, 2018 and 2017, as cash flow hedges.

As at December 31, 2018, the Partnership was committed to the following foreign currency forward contracts:

Contract Amount in Foreign Currency (thousands)	Fair Value / Carrying Amount of Asset/(Liability) (in thousands of U.S. Dollars)	Average Forward Rate[1]	Expected Maturity 2019 (in thousands of U.S. Dollars)	2020

Norwegian Krone	425,000	(4,588)	7.96	47,809	5,567
Euro	12,000	(62)	0.86	13,977	—
		(4,650)		61,786	5,567

(1) Average forward rate represents the contracted amount of foreign currency one U.S. Dollar will buy.

In connection with its issuance of NOK bonds, the Partnership entered into cross currency swaps pursuant to which it receives the principal amount in NOK on the repayment and maturity dates, in exchange for payments of a fixed U.S. Dollar amount. In addition, the cross currency swaps exchange a receipt of floating interest in NOK based on NIBOR plus a margin for a payment of U.S. Dollar fixed interest. The purpose of the cross currency swaps is to economically hedge the foreign currency exposure on the payment of interest and repayments of principal amounts of the Partnership's NOK bonds due through 2019 (see note 8). In addition, the cross currency swaps economically hedge the interest rate exposure on the NOK bonds. The Partnership has not designated, for accounting purposes, these cross currency swaps as cash flow hedges of its NOK bonds. During 2018 and 2017, the Partnership settled certain of these cross currency swaps and incurred realized losses during the years ended December 31, 2018 and 2017, which is included in foreign currency exchange loss in the consolidated statements of (loss) income.

As at December 31, 2018, the Partnership was committed to the following cross currency swaps:

Principal Amount NOK (thousands)	Principal Amount USD (thousands)	Floating Rate Receivable Reference Rate	Margin	Fixed Rate Payable	Fair Value / Asset (Liability)	Remaining Term (years)
95,000	15,409	NIBOR	4.25 %	7.45 %	(4,538)	0.1

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

Interest Rate Risk

The Partnership enters into interest rate swaps, which exchange a receipt of floating interest for a payment of fixed interest, to reduce the Partnership's exposure to interest rate variability on its outstanding floating-rate debt. During the years ended December 31, 2018 and 2017, certain of these interest rate swaps were designated in qualifying hedging relationships and hedge accounting was applied in the consolidated financial statements or within our equity-accounted for investments. During 2018, the Partnership de-designated, for accounting purposes, certain interest rate swaps and as at December 31, 2018, has not designated, for accounting purposes, any of its interest rate swaps as hedges of variable rate debt. Certain of the Partnership's interest rate swaps are secured by vessels.

As at December 31, 2018, the Partnership and its consolidated subsidiaries were committed to the following interest rate swap agreements:

	Interest Rate Index	Notional Amount $	Fair Value / Carrying Amount of Assets (Liability) $	Weighted-Average Remaining Term (years)	Fixed Interest Rate (%) [1]
U.S. Dollar-denominated interest rate swaps [2]	LIBOR	700,000	(83,965)	6.5	4.1 %
U.S. Dollar-denominated interest rate swaps [3]	LIBOR	766,145	(23,109)	3.6	3.2 %
		1,466,145	(107,074)		

(1) Excludes the margin the Partnership pays on its variable-rate debt, which as at December 31, 2018, ranged from 0.90% to 4.30%.
(2) Notional amount remains constant over the term of the swap.
(3) Principal amount reduces quarterly or semi-annually.

For the periods indicated, the following tables present the effective and ineffective portion of the gain (loss) on interest rate swap agreements designated and qualifying as cash flow hedges. The following tables exclude any interest rate swap agreements designated and qualifying as cash flow hedges in the Partnership's equity accounted joint ventures.

Year Ended December 31, 2018				Year Ended December 31, 2017			
Effective Portion Recognized in AOCI [1]	Effective Portion Reclassified from AOCI [2]	Ineffective Portion [3]		Effective Portion Recognized in AOCI [1]	Effective Portion Reclassified from AOCI [2]	Ineffective Portion [3]	
(2,495)	102	—	Interest expense	(19)	(1,186)	(7)	Interest expense
(2,495)	102	—		(19)	(1,186)	(7)	

Year Ended December 31, 2016		
Effective Portion Recognized	Effective Portion Reclassified	Ineffective Portion [3]

in AOCI (1)	from AOCI (2)		
101	(64)	681	Interest expense
101	(64)	681	

(1) Effective portion of designated and qualifying cash flow hedges recognized in accumulated other comprehensive income (or AOCI).
(2) Effective portion of designated and qualifying cash flow hedges recorded in AOCI during the term of the hedging relationship and reclassified to earnings.
(3) Ineffective portion of designated and qualifying cash flow hedges.

As at December 31, 2018, the Partnership had multiple interest rate swaps, cross currency swaps and foreign currency forward contracts governed by certain master agreements. Each of the master agreements provides for the net settlement of all derivatives subject to that master agreement through a single payment in the event of default or termination of any one derivative. The fair value of these derivatives is presented on a gross basis in the Partnership's consolidated balance sheets. As at December 31, 2018, these derivatives had an aggregate fair value asset amount of nil and an aggregate fair value liability amount of $91.1 million (December 31, 2017 - an aggregate fair value asset amount of $0.3 million and an aggregate fair value liability amount of $157.4 million). As at December 31, 2018, the Partnership had $1.2 million (December 31, 2017 - $4.1 million) on deposit with the relevant counterparties as security for cross currency swap liabilities under certain master agreements. The deposit is presented in restricted cash on the consolidated balance sheet.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

Tabular disclosure

The following table presents the location and fair value amounts of derivative instruments, segregated by type of contract, on the Partnership's balance sheets.

	Other current assets $	Other assets $	Accrued liabilities $	Current portion of derivative liabilities $	Derivative liabilities $
As at December 31, 2018					
Foreign currency contracts	—	—	—	(4,225)	(425)
Cross currency swaps	—	—	(96)	(4,442)	—
Interest rate swaps	1,028	2,075	(1,625)	(14,623)	(93,929)
	1,028	2,075	(1,721)	(23,290)	(94,354)
As at December 31, 2017					
Foreign currency contracts	347	28	—	(665)	(67)
Cross currency swaps	—	—	(916)	(4,412)	(38,678)
Interest rate swaps	233	1,565	(3,883)	(37,438)	(128,724)
	580	1,593	(4,799)	(42,515)	(167,469)

Total realized and unrealized gain (loss) of interest rate swaps and foreign currency forward contracts that are not designated for accounting purposes as cash flow hedges are recognized in earnings and reported in realized and unrealized gain (loss) on derivative instruments in the consolidated statements of (loss) income for the years ended December 31, 2018, 2017 and 2016 as follows:

	Year Ended December 31, 2018 $	Year Ended December 31, 2017 $	Year Ended December 31, 2016 $
Realized (loss) gain on derivative instruments			
Interest rate swaps	(38,011)	(78,296)	(52,819)
Foreign currency forward contracts	(1,228)	900	(7,153)
	(39,239)	(77,396)	(59,972)
Unrealized gain (loss) on derivative instruments			
Interest rate swaps	56,420	33,114	29,937
Foreign currency forward contracts	(4,373)	1,429	9,722
	52,047	34,543	39,659
Total realized and unrealized gain (loss) on derivative instruments	12,808	(42,853)	(20,313)

Realized and unrealized (loss) gain of cross currency swaps are recognized in earnings and reported in foreign currency exchange loss in the consolidated statements of (loss) income for the years ended December 31, 2018, 2017 and 2016 as follows:

	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
	$	$	$
Realized loss	(39,647)	(84,205)	(53,497)
Unrealized gain	38,648	91,914	46,127
Total realized and unrealized (loss) gain on cross currency swaps	(999)	7,709	(7,370)

The Partnership is exposed to credit loss in the event of non-performance by the counterparties, all of which are financial institutions, to the foreign currency forward contracts and the interest rate swap agreements. In order to minimize counterparty risk, to the extent possible and practical, interest rate swaps are entered into with different counterparties to reduce concentration risk.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

13. Income Taxes

The significant components of the Partnership's deferred tax assets and liabilities are as follows:

	December 31, 2018 $	December 31, 2017 $
Deferred tax assets:		
Tax losses carried forward (1)	251,240	120,789
Other	2,887	6,204
Total deferred tax assets	254,127	126,993
Deferred tax liabilities:		
Vessels and equipment	17,018	14,046
Other	5,531	985
Total deferred tax liabilities	22,549	15,031
Net deferred tax assets	231,578	111,962
Valuation allowance	(224,593)	(85,560)
Net deferred tax assets	6,985	26,402
Disclosed in:		
Deferred tax asset	9,168	28,110
Other long-term liabilities	2,183	1,708
Net deferred tax assets	6,985	26,402

(1) As at December 31, 2018, the income tax losses carried forward of $1,040.4 million (December 31, 2017 - $509.8 million) are available to offset future taxable income in the applicable jurisdictions, of which $651.9 million can be carried forward indefinitely, $0.4 million will expire in 2019, $0.5 million will expire in 2020, $0.4 million will expire in 2021, $0.5 million will expire in 2022, $2.2 million will expire in 2023, $0.3 million will expire in 2024, $0.6 million will expire in 2025, $0.1 million will expire in 2026 and $383.3 million will expire in 2034.

The components of the provision for income taxes are as follows:

	Year Ended December 31, 2018 $	Year Ended December 31, 2017 $	Year Ended December 31, 2016 $
Current	(4,051)	(1,772)	(3,954)
Deferred	(18,606)	1,870	(4,854)
Income tax (expense) recovery	(22,657)	98	(8,808)

The Partnership operates in countries that have differing tax laws and rates. Consequently, a consolidated weighted average tax rate will vary from year to year according to the source of earnings or losses by country and the change in applicable tax rates. Reconciliations of the tax charge related to the current year at the applicable statutory income tax rates and the actual tax charge related to the current year are as follows:

Year Ended	Year Ended	Year Ended

	December 31, 2018	December 31, 2017	December 31, 2016
	$	$	$
Net (loss) income before taxes	(101,288)	(299,540)	53,283
Net (loss) income not subject to taxes	(253,605)	(244,045)	(19,706)
Net income (loss) subject to taxes	152,317	(55,495)	72,989
At applicable statutory tax rates	28,437	(15,784)	12,972
Permanent differences	(23,179)	2,424	(13,277)
Adjustments related to currency differences	(338)	5,847	(1,869)
Valuation allowance	17,737	7,415	10,982
Tax expense (recovery) related to current year	22,657	(98)	8,808

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

The following is a tabular reconciliation of the Partnership's total amount of unrecognized tax benefits at the beginning and end of 2018, 2017 and 2016:

	Year Ended December 31, 2018 $	Year Ended December 31, 2017 $	Year Ended December 31, 2016 $
Balance of unrecognized tax benefits as at beginning of the year	1,410	2,174	4,047
Decreases for positions related to prior years	(189)	(930)	(3,376)
Increases for positions related to the current year	375	166	1,503
Balance of unrecognized tax benefits as at end of the year	1,596	1,410	2,174

The Partnership does not presently anticipate such uncertain tax positions will significantly increase or decrease in the next 12 months; however, actual developments could differ from those currently expected. The tax years 2010 through 2018 remain open to examination by some of the taxing jurisdictions in which the Partnership is subject to tax.

The interest and penalties on unrecognized tax benefits included in the tabular reconciliation above are not material.

14.Commitments and Contingencies

a) In May 2013, the Partnership entered into an agreement with Equinor, on behalf of the field license partners, to provide an FSO unit for the Gina Krog oil and gas field located in the North Sea. A new FSO unit was converted from the Randgrid shuttle tanker to service the contract with Equinor and commenced operations in late-2017. In November 2017, the Partnership received a statement of claim from Sembcorp Marine Ltd. (or Sembcorp), the shipyard which completed the conversion of the FSO unit, relating to disputed variation orders in the amount of approximately $100 million. During the year ended December 31, 2018, the Partnership filed its defense relating to this claim. As at December 31, 2018, the Partnership has accrued its best estimate for the potential liability related to these disputes to the cost of the FSO unit conversion. The Partnership estimates that the range of possible losses, in addition to what has already been accrued as of December 31, 2018, is between nil and $14 million.

b) In August 2014, the Partnership acquired 100% of the outstanding shares of Logitel, a Norway-based company focused on high-end UMS. At the time of the transaction, affiliates of Logitel were parties to construction contracts for three UMS newbuildings ordered from the COSCO (Nantong) Shipyard (or COSCO) in China. The Partnership took delivery of one of the UMS newbuildings, the Arendal Spirit UMS, in February 2015.

In June 2016, the Partnership canceled the UMS construction contracts for the two remaining UMS newbuildings, the Stavanger Spirit and the Nantong Spirit. As a result of this cancellation, during 2016, the Partnership wrote-off $43.7 million of assets related to these newbuildings and reversed contingent liabilities of $14.5 million associated with the delivery of these assets (see notes 3 and 18). An estimate of the potential damages for the cancellation of the Stavanger Spirit newbuilding contract is based on the amount due for the final yard installment of approximately $170 million less the estimated fair value of the Stavanger Spirit. Given the unique design of the vessel as well as the lack of recent sale and purchase transactions for this type of asset, the value of this vessel, and thus ultimately the amount of potential damages that may result from the cancellation, is uncertain. During December 2017, Logitel Offshore Rig II Pte Ltd., the single-purpose subsidiary relating to the Stavanger Spirit, received a notice of arbitration from COSCO to arbitrate all disputes arising from the cancellation of the construction contract of the Stavanger Spirit UMS and during March 2018, COSCO commenced arbitration against Logitel Offshore Rig II Pte Ltd. and Logitel Offshore Pte. Ltd. claiming $186.2 million plus interest, damages and costs. Pursuant to the Stavanger Spirit newbuilding contract and related agreements, COSCO only has recourse to the single-purpose subsidiary that was a party to the Stavanger Spirit newbuilding contract and its immediate parent company, Logitel Offshore Pte. Ltd., for damages incurred. Logitel Offshore Rig II Pte Ltd. and Logitel Offshore Pte. Ltd. are disputing this claim.

The Partnership's estimate of potential damages for the cancellation of the Nantong Spirit newbuilding contract is based upon estimates of a number of factors, including accumulated costs incurred by COSCO, sub-supplier contract cancellation costs, as well as how such costs are treated under the termination provisions in the contract. The Partnership estimates that the amount of potential damages faced by it in relation to the cancellation of the Nantong Spirit contract could range between $10 million and $40 million. Pursuant to the Nantong Spirit newbuilding contract, COSCO only has recourse to the single-purpose subsidiary that was a party to the Nantong Spirit newbuilding contract, and subject to the pre-action disclosure proceedings referred to above. During June 2017, Logitel Offshore Rig III LLC, the single-purpose subsidiary relating to the Nantong Spirit, received a claim from COSCO for $51.9 million for the unpaid balance for work completed, cancellation costs and damages, and during the third quarter of 2017, COSCO commenced arbitration against Logitel Offshore Rig III LLC. Logitel Offshore Rig III LLC is disputing this claim.

As at December 31, 2018, the Partnership's subsidiaries have accrued $43 million in the aggregate related to the above claims.

c) In December 2014, the Partnership acquired the Petrojarl I FPSO unit from Teekay Corporation for $57 million. The Petrojarl I underwent upgrades at the Damen Shipyard Group’s DSR Schiedam Shipyard (or Damen) in the Netherlands prior to being moved to the Aibel AS

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

shipyard (or Aibel) in Norway where its upgrades were completed. The FPSO unit commenced operations in May 2018 under a five-year charter contract with Atlanta Field B.V. and a service agreement with QGEP.

During 2017, Damen commenced a formal arbitration with Petrojarl I L.L.C. (a wholly-owned subsidiary of the Partnership) as to the settlement of shipyard costs. During May 2018, the Partnership received a statement of case from Damen claiming $150 million for additional costs allegedly incurred by Damen in respect of the work and interest thereon. The Partnership served its defense to these claims on October 31, 2018 disputing the claims brought by Damen and bringing counterclaims against Damen (including a claim for abatement of the contract price) in excess of $100 million. As of December 31, 2018, the Partnership had not accrued for any potential liability relating to these claims as the Partnership's best estimate is that the arbitration will not result in a net award, which would require an amount to be paid to Damen in excess of amounts already paid as at December 31, 2018.

d) In October 2016, the Partnership received a claim from Royal Dutch Shell Plc (or Shell) for liquidated damages of $23.6 million based on Shell's allegation that the Petrojarl Knarr FPSO unit did not meet the completion milestone on time. In August 2017, Shell served the Partnership with a notice of arbitration. Shell is also claiming that the Partnership's inability to meet the completion milestone within the specified grace period in effect triggered a 20% reduction in the price for which Shell may purchase the Petrojarl Knarr FPSO unit from the Partnership pursuant to a purchase option agreement. In a counterclaim, the Partnership has alleged that the completion milestone was met within the grace period and that Shell caused delays due to certain defaults in Shell's specifications, as well as other events. The Partnership claims that, due to delays caused by Shell, the Partnership is entitled to the daily lease rate under the contract for the unit commencing prior to when Shell actually started paying such rate and that Shell is not entitled to a reduction in the purchase option price. The duration of the period that the Partnership claims to be entitled to receive additional daily lease payments is in dispute. Uncertainty exists as to the resolution of the various claims. The Partnership has commenced arbitration proceedings with Shell and initial claim and defense submissions have been filed. The Partnership's claims submitted in the arbitration exceed Shell's claim for liquidated damages of $23.6 million, which the Partnership estimates to be the maximum possible loss. As of December 31, 2018, the Partnership had not accrued for any potential liability relating to these claims as the Partnership's best estimate is that the arbitration will not result in awards which would require a net amount to be paid in favor of Shell.

e) In 2017, the Partnership entered into shipbuilding contracts with Samsung Heavy Industries Co., Ltd. to construct four Suezmax Dynamic Positioning 2 (or DP2) shuttle tanker newbuildings, for an aggregate fully built-up cost of approximately $602 million. These newbuilding vessels are being constructed based on the Partnership's new Shuttle Spirit design which incorporates technologies intended to increase fuel efficiency and reduce emissions, including liquefied natural gas (or LNG) propulsion technology. Upon expected delivery in late-2019 through 2020, these vessels are to provide shuttle tanker services in the North Sea, with two to operate under the Partnership's existing master agreement with Equinor, and two to operate directly within the North Sea CoA fleet. As at December 31, 2018, payments made towards these commitments were $72.9 million and the remaining payments required to be made are estimated to be $248.9 million (2019) and $279.7 million (2020). In 2018, the Partnership secured a debt facility, which as at December 31, 2018, provided total borrowings of up to $60.5 million for the newbuilding payments, of which $40.4 million was undrawn. The Partnership expects to secure additional long-term financing related to these shuttle tanker newbuildings.

In July 2018, the Partnership entered into shipbuilding contracts with Samsung Heavy Industries Co. Ltd., to construct two Aframax DP 2 shuttle tanker newbuildings, for an estimated aggregate fully built-up cost of $270 million. These newbuildings are also being constructed based on the Partnership's new Shuttle Spirit design. Upon delivery in late-2020 through early-2021, these vessels will join the Partnership's CoA portfolio in the North Sea. As at December 31, 2018, payments made towards these commitments were $12.3 million and the remaining payments required to be made are estimated to be $57.7 million (2019), $122.3 million (2020) and $77.5 million (2021). The Partnership expects to secure long-term financing related to these shuttle tanker newbuildings.

f) Despite generating $281 million of cash flows from operating activities during 2018, the Partnership had a working capital deficit of $488 million as at December 31, 2018. This working capital deficit primarily relates to the scheduled maturities and repayments of $554 million of outstanding debt during the 12 months ending December 31, 2019, which amount was classified as current as at December 31, 2018. The Partnership also anticipates making payments related to commitments to fund vessels under construction during 2019 through 2021 of approximately $776 million (see note 14e).

Based on these factors, during the one-year period following the issuance of these consolidated financial statements, the Partnership will need to obtain additional sources of financing, in addition to amounts generated from operations, to meet its obligations and commitments and minimum liquidity requirements under its financial covenants. Additional potential sources of financing include refinancing debt facilities, increasing amounts available under existing debt facilities, entering into new debt facilities, including additional long-term debt financing related to the six shuttle tanker newbuildings ordered, and extensions and redeployments of existing assets.

The Partnership is actively pursuing the funding alternatives described above, which it considers probable of completion based on the Partnership’s history of being able to raise debt and refinance loan facilities for similar types of vessels. The Partnership is in various stages of completion on these matters.

Based on the Partnership’s liquidity at the date these consolidated financial statements were issued, the liquidity it expects to generate from operations over the following year, and by incorporating the Partnership’s plans to raise additional liquidity that it considers probable of completion, the Partnership expects that it will have sufficient liquidity to enable the Partnership to continue as a going concern for at least the one-year period following the issuance of these consolidated financial statements.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

15. Supplemental Cash Flow Information

a) The following is a tabular reconciliation of the Partnership's cash, cash equivalents and restricted cash balances for the periods presented in these consolidated financial statements:

	As at December 31, 2018	As at December 31, 2017	As at December 31, 2016
	$	$	$
Cash and cash equivalents	225,040	221,934	227,378
Restricted cash [(1)]	8,540	28,360	92,265
Restricted cash - long-term [(1)]	—	—	22,644
	233,580	250,294	342,287

(1) Restricted cash as at December 31, 2018 includes amounts held in escrow as collateral on the Partnership's cross currency swaps, funds for a scheduled loan facility repayment, withholding taxes and office lease prepayments.
Restricted cash as at December 31, 2017 includes amounts held in escrow as collateral on the Partnership's cross currency swaps and funds for certain vessel upgrade costs.
Restricted cash as at December 31, 2016 includes amounts held in escrow as collateral on the Partnership's cross currency swaps, funds for certain vessel upgrade and dry dock costs and a performance bond relating to the Petrojarl Knarr FPSO unit.

b) The changes in non-cash working capital items related to operating activities for the years ended December 31, 2018, 2017 and 2016 are as follows:

	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
	$	$	$
Accounts receivable	22,320	(54,830)	34,669
Prepaid expenses and other assets	(2,104)	(6,618)	5,983
Accounts payable and accrued liabilities	(32,800)	43,113	38,627
Advances (to) from affiliate	(70,643)	51,841	(5,061)
	(83,227)	33,506	74,218

c) Cash interest paid (including realized losses on interest rate swaps) during the years ended December 31, 2018, 2017 and 2016 totaled $204.5 million, $205.0 million, and $180.9 million, respectively.

d) Income taxes paid during the years ended December 31, 2018, 2017 and 2016 totaled $2.1 million, $2.2 million and $1.5 million, respectively.

16. Total Capital and Net Income Per Common Unit

At December 31, 2018, a total of 26.7% of the Partnership's common units outstanding were held by the public. Brookfield held a total of 59.5% of the common units of the Partnership and 51% of the general partner interest. The remaining 13.8% of the common units, as well as 49% of the general partner interest, were held by subsidiaries of Teekay Corporation. At December 31, 2018, all of the Partnership's outstanding Series A Cumulative Redeemable Preferred Units (or the Series A Preferred Units), Series B Cumulative Redeemable Preferred Units (or the Series B Preferred Units) and Series E Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (or the Series

E Preferred Units) were held by entities other than Teekay Corporation, Brookfield and their affiliates.

Limited Partners' Rights

Significant rights of the limited partners include the following:

- Right of common unitholders to receive distributions of Available Cash (after deducting expenses, including estimated maintenance capital expenditures and reserves, including reserves for future capital expenditures and for anticipated future credit needs of the Partnership) within approximately 45 days after the end of each quarter.
- No limited partner shall have any management power over the Partnership's business and affairs; the general partner shall conduct, direct and manage our activities.
- The general partner may be removed if such removal is approved by common unitholders holding at least 66.66% of the outstanding units voting as a single class, including units held by the general partner and its affiliates.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

Incentive Distribution Rights

The general partner is entitled to incentive distributions if the amount the Partnership distributes to common unitholders with respect to any quarter exceeds specified target levels shown below:

Quarterly Distribution Target Amount (per unit)	Unitholders	General Partner
Minimum quarterly distribution of $0.35	99.24 %	0.76 %
Up to $0.4025	99.24 %	0.76 %
Above $0.4025 up to $0.4375	86.24 %	13.76%
Above $0.4375 up to $0.525	76.24 %	23.76%
Above $0.525	51.24 %	48.76%

During 2018, 2017 and 2016 cash distributions were below $0.35 per common unit. Consequently, the increasing percentages were not used to calculate the general partner's interest in net (loss) income for the purposes of the net (loss) income per common unit calculation for the year ended December 31, 2018, 2017 and 2016.

In the event of a liquidation, all property and cash in excess of that required to discharge all liabilities and liquidation amounts on the Series A, Series B and Series E Preferred Units will be distributed to the common unitholders and the general partner in proportion to their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of the Partnership's assets in liquidation in accordance with the partnership agreement.

Series E Preferred Units

In January 2018, the Partnership issued 4.8 million 8.875% Series E Preferred Units in a public offering for net proceeds of $116.0 million. Pursuant to the partnership agreement, distributions on the Series E Preferred Units to preferred unitholders are cumulative from the date of original issue, payable quarterly in arrears, when, as and if declared by the board of directors of the general partner. Distributions are payable on the Series E Preferred Units (i) from and including the original issue date to, but excluding, February 15, 2025 at a fixed rate equal to 8.875% per annum of the stated liquidation preference of $25.00 per unit and (ii) from and including February 15, 2025, at a floating rate equal to three-month LIBOR plus 6.407%. These units are listed on the New York Stock Exchange.

Series C-1 and Series D Preferred Units

In September 2017, the Partnership entered into a strategic partnership (the Brookfield Transaction) with Brookfield. As part of this transaction, the Partnership repurchased and subsequently canceled all of its outstanding Series C-1 Cumulative Convertible Perpetual Preferred Units (or the Series C-1 Preferred Units) and Series D Cumulative Convertible Perpetual Preferred (or the Series D Preferred Units) from existing unitholders. The Series C-1 and Series D Preferred Units, similar to the Partnership's previously outstanding Series C Preferred Units, were convertible into common units in accordance with their terms. The Series C-1 Preferred Units were repurchased for $18.20 per unit and Series D Preferred Units for $23.75 per unit, for a total cash payment of $260.2 million, which included $10.2 million of accrued and unpaid quarterly distributions, and resulted in a net accounting gain on repurchase of approximately $20.0 million, which was reflected as an equity contribution. Consideration for the repurchase of the Series D Preferred Units also included a reduction in the exercise price, from $6.05 to $4.55 per unit, of 2,250,000 of one of two tranches of warrants issued in conjunction with the Series D Preferred Units in June 2016. As at December 31, 2018 and 2017, 6,750,000 warrants originally issued in connection with the Series D Preferred Units with an exercise price of $4.55 remained outstanding.

The Series C-1 and Series D Preferred Units were originally issued in 2016. For a description of these units and attached terms and conditions, see Item 18: Financial Statements: Note 16 in the Partnership's audited consolidated financial statements filed with its Annual Report on Form 20-F for the year ended December 31, 2016.

Series D Detachable Warrants and Brookfield Transaction Warrants

Series D Detachable Warrants

In June 2016, the Partnership issued a total of 4.0 million of its 10.5% Series D Preferred Units to a group of investors and subsidiaries of Teekay Corporation. These investors and Teekay Corporation also received an aggregate of 4,500,000 warrants with an exercise price of $4.55 per unit (the $4.55 Warrants) and an aggregate of 2,250,000 warrants with an exercise price of $6.05 per unit (the $6.05 Warrants) (collectively, the Warrants).

In September 2017, the exercise price of the $6.05 warrants was reduced to $4.55 per unit, as described above. The Warrants have a seven-year term and are exercisable any time after six months following their issuance date. The Warrants may be settled either in cash or common units at the Partnership’s option. In the event of a change in control in which the Partnership is not the surviving entity, the Partnership will use commercially reasonable efforts to deliver or cause to be delivered one or more warrants in the surviving entity that has substantially similar rights, preferences and privileges as the Warrants. The Partnership filed a registration statement with respect to the common units issuable upon exercise of the Warrants, which was declared effective by the SEC on August 31, 2016.

The Warrants are recorded as permanent equity in the Partnership's consolidated balance sheets with 6,750,000 Warrants outstanding at December 31, 2018 (December 31, 2017 - 6,750,000).

Brookfield Transaction Warrants and Common Units Issued

In September 2017, as part of the Brookfield Transaction, Brookfield and Teekay Corporation invested $610.0 million and $30.0 million, respectively, in the Partnership in exchange for 244.0 million and 12.0 million common units, respectively, at a price of $2.50 per common unit, and the Partnership issued to Brookfield and Teekay Corporation 62.4 million and 3.1 million warrants, respectively (the Brookfield Transaction Warrants), with each warrant exercisable for one common unit. As part of the amended and restated Brookfield Promissory Note transaction (see note 11f), Brookfield concurrently transferred 11.4 million Brookfield Transaction Warrants and $140.0 million to Teekay Corporation to acquire a $200 million subordinated promissory note owed by the Partnership. The $637.0 million net investment in the Partnership by Brookfield and Teekay Corporation was allocated on a relative fair value basis between the 256 million common units issued to Brookfield and Teekay Corporation ($512.6 million), the Brookfield Transaction Warrants ($121.3 million), the effective extinguishment of the $200 million 2016 Teekay Corporation Promissory Note (($160.5) million) and the concurrent issuance to Brookfield of the $200 million Brookfield Promissory Note ($163.6 million) (see note 11f). The $39.5 million gain on the effective extinguishment of the subordinated promissory note was accounted for as a contribution of capital from Teekay Corporation.
The Brookfield Transaction Warrants allow the holders to acquire one common unit for each Brookfield Transaction Warrant for an exercise price of $0.01 per common unit, which are exercisable until September 25, 2024 if the Partnership's common unit volume-weighted average price is equal to or greater than $4.00 per common unit for 10 consecutive trading days.
In July 2018, Brookfield, through an affiliate, exercised its option to acquire an additional 2% of ownership interests in the Partnership's general partner from an affiliate of Teekay Corporation in exchange for 1.0 million Brookfield Transaction Warrants. As at December 31, 2018, Brookfield and Teekay Corporation held 50.0 million and 15.5 million Brookfield Transaction Warrants, respectively (December 31, 2017 - 51.0 million and 14.5 million, respectively).

Series B and Series A Preferred Units

In April 2015, the Partnership issued 5.0 million 8.50% Series B Preferred Units in a public offering with an aggregate redemption amount of $125.0 million, for net proceeds of $120.8 million. Pursuant to the partnership agreement, distributions on the Series B Preferred Units to preferred unitholders are cumulative from the date of original issue and are payable quarterly in arrears, when, as and if declared by the board of directors of the general partner. At any time on or after April 20, 2020, the Series B Preferred Units may be redeemed by the Partnership at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions to the date of redemption. These units are listed on the New York Stock Exchange.
In April 2013, the Partnership issued 6.0 million 7.25% Series A Preferred Units in a public offering with an aggregate redemption amount of $150.0 million, for net proceeds of $144.8 million. Pursuant to the partnership agreement, distributions on the Series A Preferred Units to preferred unitholders are cumulative from the date of original issue and are payable quarterly in arrears, when, as and if declared by the board of directors of the general partner. At any time on or after April 30, 2018, the Series A Preferred Units may be redeemed by the Partnership at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions to the date of redemption. These units are listed on the New York Stock Exchange.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

Net (Loss) Income Per Common Unit

	Year Ended December 31, 2018 $	December 31, 2017 $	December 31, 2016 $
Limited partners' interest in net (loss) income	(147,141)	(339,501)	(12,952)
Preferred units - periodic accretion	—	(2,380)	(1,644)
Net gain on repurchase of Series C-1 and Series D Preferred Units	—	19,637	—
Gain on modification of warrants	—	1,495	—
Additional consideration for induced conversion of Series C Preferred Units	—	—	(36,961)
Deemed contribution on exchange of Series C Preferred Units	—	—	20,231
Limited partners' interest in net (loss) income for basic net (loss) income per common unit	(147,141)	(320,749)	(31,326)
Series C-1 Preferred Units - cash distributions	—	12,650	—
Gain on repurchase of Series C-1 Preferred Units	—	(26,994)	—
Limited partners' interest in diluted net (loss) income	(147,141)	(335,093)	(31,326)
Weighted average number of common units	410,261,239	220,755,937	124,747,207
Dilutive effect of Series C-1 Preferred Units and unit based compensation	—	9,184,183	—
Common units and common unit equivalents	410,261,239	229,940,120	124,747,207
Limited partner's interest in net (loss) income per common unit			
- basic	(0.36)	(1.45)	(0.25)
- diluted	(0.36)	(1.46)	(0.25)

Limited partners’ interest in net (loss) income per common unit – basic is determined by dividing net (loss) income, after deducting the amount of net (loss) income attributable to the non-controlling interests, the general partner’s interest, the distributions on the Series A, B, and E Preferred Units, for periods prior to their exchange or repurchase, the Series C, C-1 and D Preferred Units, the periodic accretion prior to the repurchase of the Series D Preferred Units, the additional consideration to induce conversion of Series C Preferred Units and deemed contributions on exchange of Series C Preferred Units prior to their repurchase or exchange for Series C-1 Preferred Units or common units, the net gain on the repurchase of the Series C-1 and D Preferred Units and gain on the modification of warrants, by the weighted-average number of common units outstanding during the period. The distributions payable or paid on the preferred units for the year ended December 31, 2018 were $31.5 million (2017 - $42.1 million, 2016 - $45.8 million).

The computation of limited partners’ interest in net income per common unit - diluted assumes the issuance of common units for all potential dilutive securities, consisting of restricted units (see note 17), warrants and, and for periods prior to their exchange or repurchase, Series C, C-1 and D Preferred Units. Consequently, for periods prior to their repurchase, the net income attributable to limited partners’ interest is exclusive of any distributions on the Series C, C-1 and D Preferred Units, the prior periodic accretion of the Series D Preferred Units, the net gain on the repurchase of preferred units, and the gain on the modification of warrants. In addition, the weighted average number of common units outstanding has been increased assuming conversion of the restricted units and exercise of the warrants using the treasury stock method and, for periods prior to the exchange or repurchase, the Series C, C-1 and D Preferred Units having been converted to common units using the if-converted method. The computation of limited partners’ interest in net income per common unit - diluted does not assume the issuance of common units pursuant to the restricted units, warrants and, for periods prior to their exchange or repurchase, Series C, C-1 and D Preferred Units if the effect would be anti-dilutive. In periods where a loss is attributable to common unitholders all restricted units, warrants, the Series C, C-1 and D Preferred Units (for applicable periods) could have been anti-dilutive. In periods where income is allocated to common unitholders, the Series C-1 and D Preferred Units could have been anti-dilutive for periods prior to their exchange or repurchase.

For the year ended December 31, 2018, a total common unit equivalent of 72.3 million warrants and 0.1 million restricted units were excluded from the computation of limited partners' interest in net loss per common unit - diluted, as their effect was anti-dilutive. For the year ended December 31, 2017, 31.9 million common unit equivalent Series D Preferred Units, 72.3 million common unit equivalent warrants and 0.4 million restricted units were excluded from the computation of limited partners' interest in net loss per common unit - diluted, as their effect was anti-dilutive. For the year ended December 31, 2016, 40.6 million Series C, C-1 and D Preferred Units, 6.8 million common unit equivalent warrants and 0.4 million restricted units were excluded from the computation of limited partners' interest in net income per unit - diluted, as their effect was anti-dilutive.

The general partner's and common unitholders' interests in net (loss) income are calculated as if all net (loss) income was distributed according to the terms of the Partnership's partnership agreement, regardless of whether those earnings would or could be distributed. The partnership agreement does not provide for the distribution of net (loss) income; rather, it provides for the distribution of available cash, which is a contractually defined term that generally means all cash on hand at the end of each quarter less, among other things, the amount of cash

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

reserves established by the general partner's board of directors to provide for the proper conduct of the Partnership's business including reserves for maintenance and replacement capital expenditure, anticipated capital requirements and any accumulated distributions on, or redemptions of, the Series A, Series B and Series E Preferred Units, and for periods prior to their exchange or repurchase, the Series C, C-1 and D Preferred Units. Unlike available cash, net (loss) income is affected by non-cash items such as depreciation and amortization, unrealized gain or loss on derivative instruments and unrealized foreign currency translation gain or loss.
Pursuant to the partnership agreement, allocations to partners are made on a quarterly basis.
Public and Private Offerings of Common Units
The following table summarizes the issuances of common units over the three years ending December 31, 2018:

Date	Offering Type	Number of Common Units Issued	Offering Price	Gross Proceeds (i)	Net Proceeds	Use of Proceeds
				(in millions of U.S. Dollars)		
During 2016	Continuous Offering Program	5,525,310	(ii)	31.8	31.0	General corporate purposes
June 2016	Private	21,978,022	$4.55	102.0	99.5	For general corporate purposes, which included funding existing newbuilding installments and capital conversion projects.
During 2016	Payment-in-kind	4,558,624	(iii)	0.5	0.5	(iii)
June 2016	Series C Conversion	8,323,809	(iv)	0.9	0.7	(iv)
During 2017	Payment-in-kind	6,391,087	(iii)	29.8	29.8	(iii)
September 2017	Private	256,000,000	(v)	640.0	628.1	To strengthen the Partnership's capital structure and to fund the Partnership's existing growth projects.

(i) Including the General Partner's proportionate capital contribution, where applicable.
(ii) In June 2016, the Partnership implemented a replacement $100 million continuous offering program.
(iii) Common units issued as a payment-in-kind for the distributions on the Partnership's Series C-1 and D Preferred Units and on the Partnership's common units and general partner interest held by subsidiaries of Teekay Corporation and payment-in-kind for interest on the 2016 Teekay Corporation Promissory Note (see note 11e).
(iv) In June 2016, the Partnership and the holders of the Series C Preferred Units exchanged approximately 1.9 million of the Series C Preferred Units for approximately 8.3 million common units of the Partnership. The number of common units issued consisted of the approximately 1.9 million common units that would have been issuable under the original conversion terms of the Series C Preferred Units plus an additional approximately 6.4 million common units to induce the exchange (the Inducement Premium).
(v) In September 2017, as part of the Brookfield Transaction, the Partnership issued to Brookfield 244.0 million common units and the Brookfield Transaction Warrants to purchase 62.4 million common units, for gross proceeds of $610.0 million. In addition, the Partnership issued to Teekay Corporation 12.0 million common units and the Brookfield Transaction Warrants to purchase 3.1 million common units, for gross proceeds of $30.0 million. The net proceeds are exclusive of expenses allocated to the Brookfield Transaction Warrants of $1.4 million.

17. Unit Based Compensation

During the year ended December 31, 2018, a total of 293,770 common units, with an aggregate value of $0.8 million, were granted to the non-management directors of the general partner as part of their annual compensation for 2018.

The Partnership grants restricted unit-based compensation awards as incentive-based compensation to certain employees of the Partnership and Teekay Corporation's subsidiaries that provide services to the Partnership. During the years ended December 31, 2018, 2017 and 2016, the Partnership granted restricted unit-based compensation awards with respect to 1,424,058, 321,318 and 601,368 units, respectively, with aggregate grant date fair values of $3.7 million, $1.6 million and $2.4 million, respectively for 2018, 2017 and 2016, based on the Partnership's closing unit price on the grant dates. Each restricted unit is equal in value to one of the Partnership's common units. Each award represents the specified number of the Partnership's common units plus reinvested distributions from the grant date to the vesting date. The awards vest equally over three years from the grant date. Any portion of an award that is not vested on the date of a recipient's termination of service is canceled, unless the termination arises as a result of the recipient's retirement and, in this case, the award will continue to vest in accordance with the vesting schedule. Upon vesting, the awards are paid to each grantee in the form of common units or cash. As at December 31, 2018, 2017 and 2016 the Partnership had 1,456,999, 480,301 and 361,355 non-vested restricted units outstanding, respectively.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

During the year ended December 31, 2018, restricted unit-based awards with respect to a total of 342,560 common units with a fair value of $2.0 million, based on the Partnership's closing unit price on the grant date, vested and the amount paid to the grantees was made by issuing 111,336 common units and by paying $0.4 million in cash.

During the year ended December 31, 2017, restricted unit-based awards with respect to a total of 255,370 common units with a fair value of $2.2 million, based on the Partnership's closing unit price on the grant date, vested and the amount paid to the grantees was made by issuing 83,060 common units and by paying $0.6 million in cash.

During the year ended December 31, 2016, restricted unit-based awards with respect to a total of 76,637 common units with a fair value of $2.0 million, based on the Partnership's closing unit price on the grant date, vested and the amount paid to the grantees was made by issuing 25,286 common units and by paying $0.2 million in cash.

The Partnership recorded unit-based compensation expense of $1.4 million, $0.9 million and $1.9 million, during the years ended December 31, 2018, 2017 and 2016, respectively, in general and administrative expenses in the Partnership's consolidated statements of (loss) income.

As of December 31, 2018 and December 31, 2017, liabilities relating to cash settled restricted unit-based compensation awards of $0.7 million and $0.5 million, respectively, were recorded in accrued liabilities on the Partnership's consolidated balance sheets. As at December 31, 2018, the Partnership had $1.4 million of non-vested awards not yet recognized, which the Partnership expects to recognize over a weighted average period of 0.7 years.

18. (Write-down) and Gain (Loss) on Sale of Vessels and Conventional Tankers Dispositions

(Write-down) and Gain (Loss) on Sale of Vessels

In 2018, the carrying value of the Petrojarl Cidade de Rio das Ostras and Piranema Spirit FPSO units were written down to their estimated fair values, using a discounted cash flow valuation, as a result of a reassessment of the future redeployment assumptions for both units. The Partnership's consolidated statement of loss for the year ended December 31, 2018 includes a $180.2 million write-down related to these vessels. The write-down is included in the Partnership's FPSO segment.

In 2018, the carrying value of the HiLoad DP unit was written down to $nil using a discounted cash flow valuation. The unit was written down as a result of a settlement received from Petrobras (see note 5) and a change in the operating plan for the unit. The Partnership's consolidated statement of loss for the year ended December 31, 2018 includes a $19.2 million write-down related to this unit. The HiLoad DP unit had previously been written down to its estimated fair value using a discounted cash flow valuation in 2017, as a result of a change in expectations for the future employment opportunities for the unit and the unit proceeding into lay-up. The Partnership's consolidated statement of loss for the year ended December 31, 2017 includes a $26.3 million write-down related to this unit. The write-downs are included in the Partnership's shuttle tanker segment.

In 2018, the carrying value of the Nordic Spirit and Stena Spirit shuttle tankers were written down to their estimated fair values, using appraised values, due to the redelivery of these vessels from their charterer after completing their bareboat charter contracts in May 2018 and the resulting change in the expectations for the future opportunities for the vessels. The Nordic Spirit was classified as held for sale on the Partnership's consolidated balance sheet as at December 31, 2018. The Partnership's consolidated statement of loss for the year ended December 31, 2018 includes a $29.7 million write-down related to these vessels, of which $14.8 million is included in a 50%-owned subsidiary of the Partnership. The write-down is included in the Partnership's shuttle tanker segment.

In 2018, the Partnership sold the 1998-built shuttle tankers, the Navion Scandia and Navion Britannia, for net proceeds of $10.8 million and $10.4 million, respectively. The Partnership's consolidated statement of loss for the year ended December 31, 2018 includes a $5.3 million gain related to the sale of these vessels. The gain on sale is included in the Partnership's shuttle tanker segment.

In 2017, the carrying value of two FPSO units were written down to their estimated fair value, using a discounted cash flow valuation. The Petrojarl I FPSO unit was written down to its estimated fair value, as a result of increasing costs associated with additional upgrade work required and estimated liquidated damages to the charterer associated with the delay in the commencement of the unit's operations. During 2017, the Petrojarl I FPSO unit was moved from the Damen Shipyard in the Netherlands to complete upgrades at the Aibel AS shipyard in Norway. Upon arrival at the Aibel AS shipyard, it was determined that additional upgrade work was required, resulting in a further increase in costs and a further delay of the commencement of the FPSO unit's operations until the second quarter of 2018. In addition, during 2017, the Petrojarl Cidade de Rio das Ostras FPSO unit was written down to its estimated fair value, using a discounted cash flow valuation, as a result of an expected change in the operating plans for the unit resulting from receiving confirmation from the charterer that it planned to redeliver the unit upon completion of the firm charter contract in January 2018. The Partnership's consolidated statement of loss for the year ended December 31, 2017 includes an aggregate $265.2 million write-down related to these units. The write-downs are included in the Partnership's FPSO segment.

In 2017, the Nordic Brasilia and Nordic Rio shuttle tankers were written down to their estimated fair values, using appraised values, due to the redelivery of these vessels from their charterer after completing their bareboat charter contracts in 2017 and a resulting change in expectations for the future opportunities and operating plans for the vessels. The Partnership's consolidated statement of loss for the year ended December 31, 2017 includes a $25.2 million write-down related to these units, of which $10.8 million is included in a 50%-owned subsidiary of the Partnership. The write-downs are included in the Partnership's shuttle tanker segment.

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

In 2017, the Partnership sold a 1999-built shuttle tanker, the Navion Marita, for gross proceeds of $5.7 million, which was the approximate carrying value of the vessel at the time of sale. The shuttle tanker had previously been written down to its estimated fair value as a result of the expected sale of the vessel, and the Partnership's consolidated statement of income for the year ended December 31, 2017, includes a $5.1 million write-down related to the vessel. In 2016, the carrying value of the Navion Marita had been written down to its estimated fair value, using an appraised value as a result of fewer opportunities to trade the vessel in the conventional tanker market. The Partnership's consolidated statement of income for the year ended December 31, 2016, includes a $2.1 million write-down related to the vessel. The write-downs are included in the Partnership's shuttle tanker segment.

In 2017, the Partnership sold the Navion Saga FSO unit for gross proceeds of $7.4 million, resulting in a gain on sale of approximately $0.4 million recorded during 2017. The unit had previously been written down to its estimated fair value, using an appraised value as a result of the expected sale of the unit. The Partnership's consolidated statement of income for the year ended December 31, 2016 includes a $1.7 million write-down related to this unit. The gain on sale and write-down of this unit are included in the Partnership's FSO segment.

In 2016, the Partnership sold a 1992-built shuttle tanker, the Navion Torinita, for net proceeds of $5.0 million, which was the approximate carrying value of the vessel at the time of sale, and sold a 1995-built shuttle tanker, the Navion Europa, for net proceeds of $14.4 million, for which the Partnership recorded a gain on sale of $6.8 million, in a 67%-owned subsidiary of the Partnership. The $6.8 million gain on sale includes both the Partnership's interest and the non-controlling interest. The gain on sale is included in the Partnership's shuttle tanker segment.

In 2016, the Partnership canceled the UMS construction contracts for its two UMS newbuildings. As a result, the carrying values of these two UMS newbuildings were written down to $nil. The Partnership's consolidated statements of income for the year ended December 31, 2016 includes a $43.7 million write-down related to these two UMS newbuildings (see notes 3 and 14b). The write-down is included in the Partnership's UMS segment.

Conventional Tankers Dispositions

In March 2016, the time-charter contract with a subsidiary of Teekay Corporation for a 2004-built conventional tanker, the Kilimanjaro Spirit, was terminated by the Partnership. The Partnership concurrently received an early termination fee of $4.0 million from Teekay Corporation. Immediately following the charter termination, the Partnership sold the Kilimanjaro Spirit for net proceeds of $26.7 million and also sold a 2003-built conventional tanker, the Fuji Spirit, for net proceeds of $23.7 million, which were the approximate carrying values of the vessels at the time of sale. As part of the sale of these vessels, the Partnership is in-chartering these vessels for a period of three years each, both with an additional one-year extension option. The vessels are currently trading in the spot conventional market.

The following table summarizes the pretax profit and components thereof for the Fuji Spirit and Kilimanjaro Spirit for the periods presented in the consolidated statements of income, while these vessels were owned by the Partnership:

	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
	$	$	$
Revenues	—	—	8,030
Voyage expenses	—	—	(435)

Vessel operating expenses	—	—	(1,340)
General and administrative	—	—	(1)
Income from vessel operations	—	—	6,254
Interest expense	—	—	(142)
Foreign currency exchange loss	—	—	(4)
Net income before income tax expense	—	—	6,108

19. Investment in Equity Accounted Joint Ventures

In October 2014, the Partnership sold a 1995-built shuttle tanker, the Navion Norvegia, to OOGTK Libra GmbH & Co KG (or Libra Joint Venture), a 50/50 joint venture of the Partnership and Ocyan S.A. (or Ocyan) which vessel was converted to a new FPSO unit for the Libra field in Brazil. The FPSO unit commenced operations in late-2017. Included in the joint venture is a ten-year plus construction period loan facility, which as at December 31, 2018 had an outstanding balance of $654.2 million. The interest payments of the loan facility are based on LIBOR, plus a margin of 2.65%. The final payment under the loan facility is due in October 2027. In addition, the Libra Joint Venture entered into ten-year interest rate swap agreements, with an aggregate notional amount of $588.8 million as at December 31, 2018, which amortizes quarterly over the term of the interest rate swap agreements. These interest rate swap agreements exchange the receipt of LIBOR-based interest for the payment of a weighted average fixed rate of 2.51%. These interest rate swap agreements are not designated in qualifying cash flow hedging relationships for accounting purposes.

In June 2013, the Partnership acquired Teekay Corporation’s 50% interest in OOG TKP FPSO GmbH & Co KG, a joint venture with Ocyan, which owns the Itajai FPSO unit. Included in the joint venture is an eight-year loan facility, which as at December 31, 2018 had an outstanding balance of $138.2 million. The interest payments of the loan facility are based on LIBOR, plus a margin of 2.15%. The final payment under the loan facility is due in October 2021. The Partnership has guaranteed its 50% share of the loan facility. In addition, the joint venture entered

TEEKAY OFFSHORE PARTNERS L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts stated in thousands of U.S. Dollars, except unit and per unit data or unless otherwise indicated)

into ten-year interest rate swap agreements with an aggregate notional amount of $123.4 million as at December 31, 2018, which amortizes semi-annually over the term of the interest rate swap agreements. These interest rate swap agreements exchange the receipt of LIBOR-based interest for the payment of a fixed rate of 2.63%. These interest rate swap agreements are not designated in qualifying cash flow hedging relationships for accounting purposes.

As at December 31, 2018 and 2017, the Partnership had total investments of $212.2 million and $169.9 million, respectively, in equity accounted joint ventures. No indicators of impairment existed at December 31, 2018 and 2017.

The following table presents aggregated summarized financial information assuming a 100% ownership interest in the Partnership's equity accounted joint ventures. The results included are for the Itajai FPSO joint venture and the Libra Joint Venture.

	As at December 31,	
	2018	2017
	$	$
Cash and cash equivalents	89,634	167,381
Other assets - current	58,574	26,994
Vessels and equipment	1,152,039	1,215,451
Other assets - non-current	37,424	51,908
Current portion of long-term debt	90,063	179,701
Other liabilities - current	49,714	59,840
Long-term debt	684,538	771,573
Other liabilities - non-current	96,147	114,115

	Year ended December 31,		
	2018	2017	2016
	$	$	$
Revenues	264,215	90,662	80,999
Income from vessel operations	119,774	43,422	42,380
Realized and unrealized (loss) gain on derivative instruments	(7,047)	(139)	1,608
Net income	78,916	28,884	35,866

The Partnership does not control its equity-accounted vessels and as a result, the Partnership does not have the unilateral ability to determine whether the cash generated by its equity-accounted vessels is retained within the entities in which the Partnership holds the equity-accounted investments or distributed to the Partnership and other owners. In addition, the Partnership does not control the timing of such distributions to the Partnership and other owners.