Major Customers

The Company sells the vast majority of its E&P natural gas, oil and NGL production to third-party customers through its marketing subsidiary. For the years ended December 31, 2018 and 2017, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.4% and 10.3%, respectively, of total natural gas, oil and NGL sales. In 2016, no single customer accounted for 10% or greater of our total sales. The Company believes that the loss of a major customer would not have a material adverse effect on its ability to sell its natural gas, oil and NGL production because alternative purchasers are available.

Cash and Cash Equivalents

Cash and cash equivalents are defined by the Company as short-term, highly liquid investments that have an original maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash. Management considers cash and cash equivalents to have minimal credit and market risk as the Company monitors the credit status of the financial institutions holding its cash and marketable securities. The following table presents a summary of cash and cash equivalents as of December 31, 2018 and December 31, 2017:

	For the years ended December 31,	
(in millions)	**2018**	2017
Cash	**$ 32**	$ 261
Marketable securities [1]	**169**	605
Other cash equivalents	**-**	50 [2]
Total	**$ 201**	$ 916

(1) Consists of government stable value money market funds.

(2) Consists of time deposits.

Certain of the Company's cash accounts are zero-balance controlled disbursement accounts. The Company presents the outstanding checks written against these zero-balance accounts as a component of accounts payable in the accompanying consolidated balance sheets. Outstanding checks included as a component of accounts payable totaled $34 million and $17 million as of December 31, 2018 and 2017, respectively.

Property, Depreciation, Depletion and Amortization

Natural Gas and Oil Properties. The Company utilizes the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities, are capitalized on a country-by-country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% (standardized measure). Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas, oil and NGL prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives designated for hedge accounting, to calculate the ceiling value of their reserves. Decreases in market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments.

Costs associated with unevaluated properties are excluded from the amortization base until the properties are evaluated or impairment is indicated. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and related capitalized interest are initially excluded from the amortization base. Leasehold costs are either transferred to the amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. The Company's decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on several factors, including drilling plans, availability of capital, project economics and drilling results from adjacent acreage. At December 31, 2018, the Company had a total of $1,755 million of costs excluded from the amortization base, all of which related to its properties in the United States. Inclusion of some or all of these costs in the Company's United States properties in the future, without adding any associated reserves, could result in additional ceiling test impairments.

At December 31, 2018, using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.10 per MMBtu, West Texas Intermediate oil of $65.56 per barrel and NGLs of $17.64 per barrel,