MURPHY OIL CORP /DE
Form 424B5
August 10, 2016
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Filed Pursuant to Rule 424(b)(5)
Registration No. 333-207463

The information in this preliminary prospectus supplement is not complete and may be changed. A registration statement relating to these securities is filed with the Securities and Exchange Commission and is effective. This preliminary prospectus supplements and the accompanying prospectus are not offers to sell these securities or to solicit offers to buy these securities in any jurisdiction where the offer or sale is not permitted.

Subject to completion, dated August 10, 2016

Preliminary Prospectus Supplement

(To Prospectus dated October 16, 2015)

$500,000,000 % Notes Due 2024

We are offering $500,000,000 aggregate principal amount of % notes due 2024 (the notes). The notes will bear interest at the rate of % per year, payable semiannually in arrears on and of each year, commencing , 2017. The notes will mature on , 2024.

At any time prior to , 2019, we may redeem the notes, in whole or in part, at a price equal to the greater of (i) 100% of the principal amount of the notes to be redeemed or (ii) a make-whole redemption price determined by using a discount rate of the applicable treasury rate plus basis points, plus in each case, accrued and unpaid interest on the principal amount of the notes being redeemed to, but not including, the redemption date. At any time on or after , 2019, we may redeem the notes, in whole or in part, at the applicable redemption prices set forth under Description of the notes Optional Redemption , plus accrued and unpaid interest on the principal amount of the notes being redeemed to, but not including, the redemption date.

The notes will be senior unsecured obligations of Murphy Oil Corporation and will rank equally with all of Murphy Oil Corporation s other senior unsecured indebtedness from time to time outstanding.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

See Risk factors beginning on page S-17 for a discussion of certain risks that you should consider in connection with making an investment in the notes.

The notes will be a new issue of securities and currently there is no established trading market for the notes. We do not intend to list the notes on any securities exchange or any automated dealer quotation system.

	Price to public(1)	Underwriting discount	Proceeds to us, before expenses

Per note	%	%	%
Total	$	$	$

(1) Plus accrued interest from , 2016 if settlement occurs after that date.

The notes will be issued only in registered book-entry form, in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof. The underwriters expect to deliver the notes to purchasers through the facilities of The Depository Trust Company for the benefit of its participants, including Euroclear Bank S.A./N.V. and Clearstream Banking, société anonyme, on or about , 2016.

Joint Physical Book-Running Managers

J.P. Morgan BofA Merrill Lynch

Joint Book-Running Managers

BNP PARIBAS DNB Markets Scotiabank

MUFG Wells Fargo Securities

Co-Managers

Regions Securities LLC Capital One Securities Goldman, Sachs & Co.

, 2016

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We have not, and the underwriters have not, authorized anyone to provide any information other than that contained or incorporated by reference in this prospectus supplement, the accompanying prospectus or in any free writing prospectus prepared by or on behalf of us or to which we have referred you. We do not, and the underwriters do not, take any responsibility for, and can provide no assurance as to the reliability of, any other information that others may give you.

We are not, and the underwriters are not, making an offer of these securities in any jurisdiction where the offer or sale is not permitted. You should not assume that the information provided by this prospectus supplement or the accompanying prospectus is accurate as of any date other than the date on the front of this prospectus supplement or, with respect to information incorporated by reference, as of the date of that information. Our business, financial condition, results of operations and prospects may have changed since those respective dates.

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About this prospectus

This document has two parts. The first part consists of this prospectus supplement, which describes the specific terms of this offering and the notes offered. The second part is the accompanying prospectus, dated October 16, 2015, which provides more general information, some of which may not apply to this offering. If the description of the offering varies between this prospectus supplement and the accompanying prospectus, you should rely on the information in this prospectus supplement.

In this prospectus supplement, we refer to Murphy Oil Corporation and its wholly owned subsidiaries as we, our, us, the Company, Murphy C or Murphy unless the context clearly indicates otherwise.

Before purchasing any notes, you should carefully read both this prospectus supplement and the accompanying prospectus, together with the additional information in the documents we have listed under the heading Where you can find more information.

Where you can find more information

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission (the SEC). You may read and copy any document we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the Public Reference Room. Our SEC filings are also available to the public at the SEC s web site at http://www.sec.gov.

The SEC allows us to incorporate by reference into this prospectus supplement the information we file with it, which means that we can disclose important information to you by referring you to those documents. The information incorporated by reference or deemed incorporated by reference is considered to be a part of this prospectus supplement. Information that we file with the SEC after the date of this prospectus supplement will update and supersede this information. We incorporate by reference the documents listed below and any future filings made with the SEC under Sections 13(a), 13(c), 14, or 15(d) of the Securities Exchange Act of 1934, as amended, until our offering is completed:

- Our Annual Report on Form 10-K for the year ended December 31, 2015, filed on February 26, 2016;

- Our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2016, filed on May 6, 2016 and June 30, 2016, filed on August 4, 2016;

- Our Definitive Proxy Statement on Schedule 14A filed on March 28, 2016 (solely to the extent incorporated by reference into Part III of our Annual Report on Form 10-K); and

- Our Current Reports on Form 8-K filed on January 28, 2016 (excluding Item 2.02), February 5, 2016, May 2, 2016, May 12, 2016, May 16, 2016, June 27, 2016, August 4, 2016 and August 10, 2016.

You may request a free copy of these filings by writing to, or telephoning, us at the following address and phone number:

Corporate Secretary

Murphy Oil Corporation

P.O. Box 7000

El Dorado, Arkansas 71731-7000

(870) 862-6411

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Forward-looking statements

This prospectus supplement and the accompanying prospectus, including the documents we incorporate by reference, contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements, which express management s current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of Murphy s exploration programs, the Company s ability to maintain production rates and replace reserves, customer demand for Murphy s products, adverse foreign exchange movements, political and regulatory instability, adverse developments in the U.S. or global capital markets, credit markets or economies generally and uncontrollable natural hazards, as well as those contained under the caption Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2015. We undertake no duty to publicly update or revise any forward-looking statements.

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Summary

This summary description of our business and the offering may not contain all of the information that may be important to you. For a more complete understanding of our business and this offering, we encourage you to read this entire prospectus supplement, the accompanying prospectus and the documents incorporated by reference herein and therein. In particular, you should read the following summary together with the more detailed information and consolidated financial statements and the notes to those statements included elsewhere in or incorporated by reference into this prospectus supplement and the accompanying prospectus.

Company overview

We are a large, diversified oil and gas exploration and production company. We have transitioned from an integrated oil company to an enterprise entirely focused on oil and gas exploration and production activities. This transition was finalized through the sale of our United Kingdom retail marketing assets during 2014, followed by the sale of our remaining downstream assets in the U.K. in the second quarter of 2015.

Our exploration and production (E&P) business explores for and produces crude oil, natural gas and natural gas liquids worldwide. Our E&P management team directs the Company s worldwide exploration and production activities. This business maintains upstream operating offices in locations around the world, including in Houston, Texas, Calgary, Alberta and Kuala Lumpur, Malaysia.

We have a reserve base of 659 million barrels of oil equivalent (MMBOE) of proved reserves, excluding synthetic oil, as of December 31, 2015, of which 62% is liquids and oil-price linked natural gas and 43% is natural gas. As of December 31, 2015, over 55% of our proved reserves, excluding synthetic oil, are proved developed. We produced approximately 165,500 barrels of oil equivalent per day (boepd), excluding synthetic oil, in our quarter ended June 30, 2016.

We have a strong record of replacing our proved reserves. Replaced proved reserves in 2015 were equal to 123% of production on a barrel of oil equivalent basis during the year and over 100% replaced for 10 consecutive years through December 31, 2015. The standardized measure of discounted future net cash flows for our proved oil and gas reserves was $3,859.1 million as of December 31, 2015, calculated in accordance with United States generally accepted accounting principles (GAAP) using a 10% annual discount factor, an unweighted average of oil and natural gas prices in effect at the beginning of each month of the year, and year-end costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates. For the twelve month period ended June 30, 2016, we recorded revenue of $2,240.8 million, net income (loss) of $(2,378.4) million, EBITDA (as defined below) of $539.7 million, EBITDAX (as defined below) of $880.9 million and Adjusted EBITDAX (as defined below) of $1,197.0 million. See Summary consolidated historical financial data for a reconciliation of EBITDA, EBITDAX and Adjusted EBITDAX to net income (loss) from continuing operations.

Our onshore operations are primarily focused in the Eagle Ford Shale in the United States and the Montney and Kaybob Duvernay plays in Canada. Excluding synthetic oil, approximately 64% of our proved reserves as of December 31, 2015 and 51% of our production in 2015 came from our North American onshore operations. We also have a significant inventory of highly economic drilling locations which we can develop at attractive returns even in a lower commodity price environment. Our offshore operations are primarily focused in the Gulf of Mexico, Malaysia and Canada. Approximately 34% of our proved reserves as of December 31, 2015 and 49% of our production in 2015 came from our offshore operations. We have a long track record of developing, operating in and generating strong cash flows from our offshore operations.

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Given weak commodity prices, we have taken significant steps to adapt to the current industry environment, including:

Divestitures:

Our Canadian subsidiary, Murphy Oil Company Ltd., closed the sale of its natural gas processing and sales pipeline assets that support our Montney natural gas fields in the Tupper area of northeastern British Columbia in April 2016. Total cash consideration received by us upon closing of the transaction was $414.1 million.

In June 2016, Murphy Oil Company Ltd. closed the sale of its 5% non-operated working interest in Syncrude Canada Ltd. to Suncor Energy Inc. The transaction was previously announced on April 27, 2016, with an effective date of April 1, 2016. This non-core asset divestiture positively impacted corporate liquidity by increasing net cash on the balance sheet before closing adjustments by $739.1 million before-tax.

The net cash proceeds of these divestitures allowed us to repay in full the outstanding borrowings under our revolving credit facility.

Prioritized capital allocation:

The significant reduction in the sales prices of crude oil has caused us to reduce capital expenditures, including development drilling and completion operations in North America.

In response to the weak commodity price environment, we have reduced exploration capital expenditures significantly compared to prior periods, and we do not expect to incur significant capital expenditures for exploration drilling while prices remain depressed. We currently anticipate total capital expenditures for the full year 2016 to be approximately $620 million, excluding the cost to acquire the Kaybob Duvernay and liquids rich Montney interests in Canada, compared to $2,187 million in 2015. This reduction in capital expenditures is primarily attributable to less development drilling in the Eagle Ford Shale area in the United States and offshore Malaysia and lower spending on exploration drilling in the Gulf of Mexico and other international operations.

We have focused our capital allocation on our large inventory of onshore North American drilling locations in the Eagle Ford, Montney and Kaybob Duvernay plays, which have attractive well economics and cash flows despite lower commodity prices.

Cost savings:

Lease operating expenses per barrel equivalent for the six months ended June 30, 2016 were 33% lower than the comparable period in 2014.

G&A expenses for the six months ended June 30, 2016 were 25% lower than the comparable period in 2014.

At December 31, 2015, Murphy had 1,258 employees, down 27% from 1,712 as of December 31, 2014.

Liquidity:

We are focused on maintaining a strong balance sheet, low leverage and strong liquidity. The net cash proceeds of our recent divestitures have been used to repay in full the borrowings under our revolving credit facility.

After giving effect to this offering, as of June 30, 2016, we would have had cash and cash equivalents of approximately $759 million, plus highly liquid Canadian government securities of $131 million and available committed borrowing capacity of approximately $1.2 billion under our revolving credit facility.

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Exploration and Production

Murphy s worldwide crude oil, condensate and natural gas liquids production in 2015 averaged 136,634 barrels per day. The Company sold 30% of its working interest in Malaysia in late 2014 and early 2015. While total liquids production decreased 10% in 2015 compared to 2014, production for the twelve month period ended December 31, 2015 was slightly above the 2014 period as adjusted for the sale in Malaysia. The increase in 2015 when adjusted for the sale was primarily due to higher crude oil and natural gas liquids production in the Eagle Ford Shale area of South Texas. The Company s worldwide sales volume of natural gas averaged 428 million cubic feet (MMCF) per day in 2015. While the Company s worldwide sales volume of natural gas in 2015 was down 4% from 2014 levels production for the twelve month period ended December 31, 2015 increased 11% compared to the 2014 period as adjusted for the Malaysia sale. The increase in natural gas sales volume in 2015 when adjusted for the sale was primarily attributable to higher gas production volumes in the Eagle Ford Shale area of South Texas and Tupper area in Western Canada. Growth in oil and gas production volumes occurred due to further development drilling in the Eagle Ford Shale and Tupper area. Total worldwide 2015 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 207,903 barrels per day, a decrease of 8% compared to 2014, but when adjusted for the sale in Malaysia increased 4% compared to 2014. If the combined sale of 30% interest in Malaysia had occurred on January 1, 2014, total pro forma daily oil and natural gas production volumes would have been approximately 135,100 barrels and 386 MMCF, respectively, in 2014. The 30% sale in Malaysia in late 2014 and early 2015 represented 2014 production of approximately 26,600 barrels of oil equivalent per day (boepd); excluding these volumes, pro forma 2014 production would have been approximately 199,400 boepd.

Total production in 2016 is currently expected to average between 173,000 and 177,000 boepd. Through June 30, 2016, total production in 2016 averaged 182,604 boepd. The projected production decrease in 2016 is primarily due to lower anticipated overall capital spending of more than 70% during the year, excluding the acquisition cost for the Kaybob Duvernay and liquids rich Montney.

United States

In the United States, Murphy primarily has production of crude oil, natural gas liquids and natural gas from fields in the Eagle Ford Shale area of South Texas and in the deepwater Gulf of Mexico. The Company produced 70,675 barrels of crude oil and gas liquids per day and approximately 87 MMCF of natural gas per day in the U.S. in 2015. These amounts represented 52% of the Company s total worldwide oil and 20% of worldwide natural gas production volumes. We hold rights to approximately 157 thousand gross acres in South Texas in the Eagle Ford Shale unconventional oil and gas play. Total 2015 oil and natural gas production in the Eagle Ford area was 54,883 barrels per day and approximately 38 MMCF per day, respectively. On a barrel of oil equivalent basis, Eagle Ford production accounted for 72% of our total U.S. production volumes in 2015. Due to scale back of drilling and infrastructure development activities related to weak oil prices, production in the Eagle Ford Shale is forecast to decline and average approximately 41,200 barrels of oil and gas liquids per day and 30 MMCF of natural gas per day in 2016. At December 31, 2015, the Company s proved reserves in the Eagle Ford Shale area totaled 207.9 million barrels of crude oil, 32.1 million barrels of natural gas liquids, and 166 billion cubic feet of natural gas.

During 2015, approximately 28% of total U.S. hydrocarbon production was produced at fields in the Gulf of Mexico. Approximately 84% of Gulf of Mexico production in 2015 was derived from four fields, including Dalmatian, Medusa, Front Runner and Thunder Hawk. We hold a 70% interest in Dalmatian in DeSoto Canyon Blocks 4, 48 and 134, 60% interest in Medusa in Mississippi Canyon Blocks 538/582, and 62.5% working interests in the Front Runner field in Green Canyon Blocks 338/339 and the Thunder Hawk field in Mississippi

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Canyon Block 734. During 2014, we acquired a 29.1% non-operated interest in the Kodiak field in Mississippi Canyon Blocks 727/771. Total daily production in the Gulf of Mexico in 2015 was 15,792 barrels of oil and gas liquids and approximately 49 MMCF of natural gas. Production in the Gulf of Mexico in 2016 is expected to total approximately 14,000 barrels of oil and gas liquids per day and 23 MMCF of natural gas per day. At December 31, 2015, Murphy had total proved reserves for Gulf of Mexico fields of 34.2 million barrels of oil and gas liquids and 66 billion cubic feet of natural gas. Total U.S. proved reserves at December 31, 2015 were 238.9 million barrels of crude oil, 35.4 million barrels of natural gas liquids, and 232 billion cubic feet of natural gas.

Canada

In Canada, the Company holds one wholly-owned heavy oil area and one wholly-owned natural gas area in the Western Canadian Sedimentary Basin (WCSB). In addition, the Company owns interests in two non-operated assets the Hibernia and Terra Nova fields offshore Newfoundland in the Jeanne d Arc Basin. The Company formerly owned a 5% interest in Syncrude Canada Ltd. in northern Alberta, but the Company sold this interest in June 2016 for net cash proceeds of $739.1 million. Daily production in 2015 in the WCSB averaged 5,456 barrels of mostly heavy oil and approximately 197 MMCF of natural gas. The Company has 101 thousand net acres of Montney mineral rights, which includes the Tupper natural gas producing area located in northeast British Columbia. The Company has 267 thousand net acres of mineral rights in the Seal field located in the Peace River oil sands area of northwest Alberta. Oil and natural gas daily production for 2016 in Western Canada, excluding Syncrude, is expected to average 3,600 barrels and approximately 212 MMCF, respectively. The expected decrease in oil production in 2016 arises from well declines and selective economic related well shut-ins in the Seal area due to lower heavy oil prices. The expected increase in natural gas volumes in 2016 is primarily the result of new wells brought on line in the Tupper area and improved performance. Total WCSB proved liquids and natural gas reserves at December 31, 2015, excluding Syncrude, were approximately 4.6 million barrels and 894 billion cubic feet, respectively.

Murphy has a 6.5% working interest in Hibernia, while at Terra Nova the Company s working interest is 10.475%. Oil production in 2015 was approximately 4,400 barrels of oil per day at Hibernia and 3,000 barrels per day at Terra Nova. Hibernia production declined in 2015 due to maturity of existing wells, while Terra Nova production was slightly higher in 2015 due to higher uptime. Oil production for 2016 at Hibernia and Terra Nova is anticipated to be approximately 5,200 barrels per day and 2,700 barrels per day, respectively. Total proved oil reserves at December 31, 2015 at Hibernia and Terra Nova were approximately 16.3 million barrels and 7.4 million barrels, respectively.

As of December 31, 2015, Murphy owned a 5% non-operated working interest in Syncrude Canada Ltd. (Syncrude), a joint venture located about 25 miles north of Fort McMurray, Alberta. Syncrude utilizes its assets, which include three coking units, to extract bitumen from oil sand deposits and to upgrade this bitumen into a high-value synthetic crude oil. Production in 2015 was about 11,700 net barrels of synthetic crude oil per day. Total proved synthetic oil reserves for Syncrude at year-end 2015 were 114.8 million barrels. Murphy closed the sale of its 5% interest in Syncrude to Suncor Energy Inc. in June 2016 for a sale price of $739.1 million.

Malaysia

In Malaysia, the Company has majority interests in eight separate production sharing contracts (PSCs). The Company serves as the operator of all these areas other than the unitized Kakap-Gumusut field. The production sharing contracts cover approximately 3.68 million gross acres. In December 2014 and January 2015, the Company sold 30% of its interest in most of its Malaysian oil and gas assets.

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Our principal executive offices are located at 300 Peach Street, P.O. Box 7000, El Dorado, Arkansas 71731-7000, and our telephone number is (870) 862-6411. Our capital stock is listed on the New York Stock Exchange under the symbol MUR. We maintain a website at http://www.murphyoilcorp.com where general information about us is available. We are not incorporating the contents of the website into this prospectus supplement or the accompanying prospectus.

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The offering

This summary highlights certain terms of the offering but does not contain all information that may be important to you. We encourage you to read this prospectus supplement and the accompanying prospectus in their entirety before making an investment decision.

Issuer	Murphy Oil Corporation
Securities offered	$500,000,000 aggregate principal amount of % notes due 2024
Maturity date	, 2024
Interest rate	% per annum
Interest payment dates	Semiannually in arrears on and of each year, commencing , 2017
	Interest on the notes will accrue from , 2016
Further issuances	We may from time to time, without the consent of the holders, create and issue additional notes having the same terms and conditions as the notes offered by this prospectus supplement in all respects, except for the issue date, issue price and, under some circumstances, the date of the first payment of interest on the notes, provided that if the additional notes of a series are not fungible with the notes for U.S. federal income tax purposes, such additional notes will have a different CUSIP.
Optional redemption	At any time prior to , 2019, we may redeem the notes, in whole or in part, at a price equal to the greater of (i) 100% of the principal amount of the notes to be redeemed or (ii) a make-whole redemption price determined by using a discount rate of the applicable treasury rate plus basis points, plus in each case, accrued and unpaid interest on the principal amount of the notes being redeemed to, but not including, the redemption date.
	At any time on or after , 2019, we may redeem the notes, in whole or in part, at the applicable redemption prices set forth under Description of the notes Optional redemption, plus accrued and unpaid interest on the principal amount of the notes being redeemed to, but not including, the redemption date.

Repurchase upon a change of control triggering event	If a change of control triggering event (as defined herein) occurs, we must offer to repurchase the notes at a purchase price equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase. See Description of the notes Repurchase upon a change of control triggering event.
Ranking	The notes:
	will be unsecured;
	will rank equally with all of our existing and future unsecured senior debt;

- will be senior to any future subordinated debt;
- will be effectively junior to our secured debt to the extent of the assets securing such debt; and
- will be effectively junior to all existing and future debt and other liabilities of, or guaranteed by our subsidiaries, including their debt and trade payables and our revolving credit facility.

As of June 30, 2016, after giving effect to this offering, our subsidiaries had $798.1 million of indebtedness, trade payables and other accrued current liabilities outstanding.

Covenants

We will issue the notes under an indenture containing covenants for your benefit. These covenants restrict our ability, with certain exceptions, to:

- incur debt secured by liens;
- permit our subsidiaries to incur or guarantee debt; and
- engage in sale/leaseback transactions.

Use of proceeds

We expect the net proceeds from this offering of notes to be approximately $491.7 million, after deducting underwriting discounts and other estimated expenses of the offering. We intend to use the net proceeds from the offering of the notes for general corporate purposes, which may include the repayment, repurchase or redemption of our 2.5% notes due 2017. See Use of proceeds.

Book-entry form

The notes will be issued in book-entry form and will be represented by global certificates deposited with, or on behalf of, The Depository Trust Company (DTC) and registered in the name of a nominee of DTC. Beneficial interests in any of the notes will be shown on, and transfers will be effected only through, records maintained by DTC or its nominee and any such interest may not be exchanged for certificated securities, except in limited circumstances.

Absence of a public market for the notes

The notes will be a new issue of securities and there is currently no established trading market for the notes. Accordingly, we cannot assure you as to the development or liquidity of any market for the notes. The underwriters have advised us that they currently intend to make a market in the notes. However, they are not obligated to do

	so, and they may discontinue any market making with respect to the notes without notice.
U.S. federal income tax consequences	For the U.S. federal income tax consequences to non-U.S. holders (as defined herein) of the holding and disposition of the notes, see Material U.S. federal income tax considerations for Non-U.S. Holders in this prospectus supplement.
Listing	We do not intend to apply for a listing of the notes on any securities exchange or any automated dealer quotation system.
Trustee	U.S. Bank National Association

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Summary consolidated historical financial data

We have provided in the tables below summary consolidated historical financial data. We have derived the statement of income data and other financial data for the six months ended June 30, 2016 and 2015, and for each of the years in the three-year period ended December 31, 2015, and the balance sheet data as of June 30, 2016 and 2015, and as of December 31 for each of the three years in the three-year period ended December 31, 2015, from our unaudited and audited consolidated financial statements. You should read the following financial information in conjunction with our consolidated financial statements and related notes that we have included elsewhere and incorporated by reference in this prospectus supplement and the accompanying prospectus. In the opinion of our management, the unaudited consolidated financial statements have been prepared on the same basis as the audited consolidated financial statements and include all adjustments necessary for a fair presentation of the information set forth therein. The interim results set forth below are not necessarily indicative of results for the year ending December 31, 2016 or for any other period.

The financial data for the twelve-month period ended June 30, 2016 in the following tables is presented for informational purposes only. Such twelve-month period is not a financial reporting period in accordance with GAAP and should not be considered in isolation from or as a substitute for our consolidated historical financial statements. The statements of operations information for such twelve-month period is derived by subtracting our statements of operations information for the six months ended June 30, 2015 from our statements of operations information for the year ended December 31, 2015 and adding our statements of operations information for the six months ended June 30, 2016.

(in thousands, except ratios)	Twelve months ended June 30, 2016 (unaudited)	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015 (unaudited)	Year Ended December 31, 2015	2014	2013
Statement of Income Data:						
Total revenues	$ 2,240,800	$ 867,757	$ 1,660,037	$ 3,033,080	$ 5,476,084	$ 5,390,089
Costs and Expenses:						
Lease operating expenses	$ 688,029	$ 315,633	$ 459,910	$ 832,306	$ 1,089,888	$ 1,252,812
Severance and ad valorem taxes	52,036	26,076	39,834	65,794	107,215	87,331
Exploration expenses, including undeveloped lease amortization	341,275	64,044	193,693	470,924	513,600	502,215
Selling and general expenses	281,140	140,620	166,143	306,663	364,004	379,167
Depreciation, depletion and amortization	1,276,795	541,388	884,417	1,619,824	1,906,247	1,553,394
Impairment of assets	2,588,244	95,088		2,493,156	51,314	21,587
Accretion of asset retirement obligations	49,617	24,471	23,519	48,665	50,778	48,996
	282,001			282,001		

Deepwater rig contract exit costs						
Interest expense	131,848	67,119	59,936	124,665	136,424	124,423
Interest capitalized	(6,531)	(2,449)	(3,208)	(7,290)	(20,605)	(52,523)
Other expenses (benefit)	7,090	(7,932)	63,612	78,634	24,949	
Total costs and expenses	5,691,544	1,264,058	1,887,856	6,315,342	4,223,814	3,917,402
Income (loss) from continuing operations before income taxes	(3,450,744)	(396,301)	(227,819)	(3,282,262)	1,252,270	1,472,687
Income tax expense (benefit)	(1,083,848)	(199,721)	(142,363)	(1,026,490)	227,297	584,550
Income (loss) from continuing operations	(2,366,896)	(196,580)	(85,456)	(2,255,772)	1,024,973	888,137
Income (loss) from discontinued operations, net of income taxes(1)	(11,534)	708	(2,819)	(15,061)	(119,362)	235,336
Net income (loss)	$ (2,378,430)	$ (195,872)	$ (88,275)	$ (2,270,833)	$ 905,611	$ 1,123,473

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(in millions, except ratios)	Twelve months ended June 30, 2016 (unaudited)	Six Months Ended June 30, 2016 (unaudited)	Six Months Ended June 30, 2015 (unaudited)	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2013
Other Financial Data:						
Net cash provided by operating activities	$ 581.5	$ 113.4	$ 715.2	$ 1,183.4	$ 3,048.6	$ 3,210.7
Capital expenditures(2)	1,505.7	463.6	1,145.1	2,187.2	3,769.3	4,120.6
EBITDA(3)	539.6	304.9	713.3	948.1	3,325.6	3,119.6
EBITDAX(3)	880.9	368.9	907.0	1,419.0	3,839.2	3,621.8
Adjusted EBITDAX(3)	1,197.2	473.5	911.8	1,635.3	3,886.9	3,673.1
Ratio of EBITDA to interest expense(3)	4.1	4.5	11.9	7.6	24.4	25.1
Ratio of earnings to fixed charges(4)(5)	*	*	*	*	7.9	9.5

(in thousands)	As of June 30, 2016 (unaudited)	As of June 30, 2015 (unaudited)	As of December 31, 2015	As of December 31, 2014	As of December 31, 2013
Balance Sheet Data:					
Working capital	$ 157,106	$ 692,645	$ (226,213)	$ 131,262	$ 284,612
Net property, plant and equipment	8,565,485	12,577,749	9,818,365	13,331,047	13,481,055
Total assets	9,914,632	15,149,964	11,493,812	16,723,738	17,509,484
Long-term debt	2,435,486	3,264,868	3,040,594	2,517,669	2,936,563
Total debt including current maturities	2,455,497	3,279,810	3,059,475	2,983,057	2,962,812
Stockholders equity	5,171,693	7,866,046	5,306,728	8,573,434	8,595,730

(1) Discontinued operations presented here principally include:

(i) U.S. retail marketing operations spun-off to shareholders on August 30, 2013. Results of operations are included in our financial statements through the date of spin-off;

(ii) U.K. refining and marketing operations. We decommissioned the Milford Haven refinery units and completed the sale of our remaining downstream assets in the U.K. in the second quarter of 2015 for cash proceeds of $5.5 million. We have accounted for the U.K. downstream business as discontinued operations for all periods presented; and

(iii) U.K. oil and gas assets sold through a series of transactions in the first half of 2013. Our financial statements include the results of operations through the respective dates the asset were sold, plus the cumulative gain realized upon sale.

(2) Capital expenditures presented here include accruals for incurred but unpaid capital activities, while property additions and dry holes in the Statements of Cash Flows are cash-based capital expenditures

and do not include capital accruals and geological, geophysical and certain other exploration expenses that are not eligible for capitalization under oil and gas accounting rules.

(3) EBITDA means earnings from continuing operations before interest expense, income taxes, depreciation, depletion and amortization and impairment of properties. EBITDAX means earnings from continuing operations before interest expense, income taxes, depreciation, depletion and amortization, impairment of properties and exploration expenses. Adjusted EBITDAX means earnings from continuing operations before interest expense, income taxes, depreciation, depletion and amortization, impairment of properties, exploration expenses, restructuring costs, mark-to-market (gain) loss, long-term incentive plan expense, (gain) loss on foreign currency, accretion expense, rig contract exist costs and other non-recurring (gains) expenses, less interest income.

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Management has included a presentation of EBITDA, EBITDAX and Adjusted EBITDAX in this prospectus supplement because some debt investors use this data as indicators of a company s ability to service debt. However, EBITDA, EBITDAX and Adjusted EBITDAX are not GAAP measures and may not be comparable to similarly titled items of other companies. You should not consider EBITDA, EBITDAX or Adjusted EBITDAX as an alternative to net income or any other generally accepted accounting principles measure of performance, as indicators of our operating performance, or as measures of liquidity. EBITDA, EBITDAX and Adjusted EBITDAX do not represent funds available for management s discretionary use because certain future cash expenditures are not reflected in the EBITDA, EBITDAX or Adjusted EBITDAX presentation. It should also be noted that all companies do not calculate EBITDA, EBITDAX or Adjusted EBITDAX in the same manner and, accordingly, EBITDA, EBITDAX and Adjusted EBITDAX presented in this prospectus supplement may not be comparable to similar measures used by other companies.

The following table is a reconciliation of EBITDA, EBITDAX and Adjusted EBITDAX to net income (loss) from continuing operations, the most directly comparable financial measure under GAAP (in millions, except ratios):

	Twelve months ended June 30, 2016 (unaudited)	Six Months Ended June 30, 2016 (unaudited)	Six Months Ended June 30, 2015 (unaudited)	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2013
Income (loss) from continuing operations	$ (2,366.9)	$ (196.6)	$ (85.5)	$ (2,255.8)	$ 1,025.0	$ 888.1
Interest expense	131.9	67.1	59.9	124.7	136.4	124.4
Interest capitalized	(6.5)	(2.4)	(3.2)	(7.3)	(20.6)	(52.5)
Income tax expense	(1,083.8)	(199.7)	(142.3)	(1,026.5)	227.3	584.6
Depreciation, depletion and amortization	1,276.8	541.4	884.4	1,619.8	1,906.2	1,553.4
Impairment of properties	2,588.2	95.1		2,493.2	51.3	21.6
EBITDA	$ 539.7	$ 304.9	$ 713.3	$ 948.1	$ 3,325.6	$ 3,119.6
Exploration expense	341.2	64.0	193.7	470.9	513.6	502.2
EBITDAX	$ 880.9	$ 368.9	$ 907.0	$ 1,419.0	$ 3,839.2	$ 3,621.8
Restructuring costs	19.3	9.3	2.6	12.6		22.4
Mark-to-market (gains) losses	10.0	79.9	(7.4)	(77.3)	(0.4)	
Long-term incentive plan expense	32.6	14.5	24.3	42.4	43.5	57.6
(Gain) loss on foreign currency	(74.4)	(22.1)	(35.7)	(88.0)	(38.5)	(73.7)
Accretion expense	49.6	24.4	23.6	48.7	50.8	48.9
Rig contract exit costs	282.0			282.0		
Interest income	(2.8)	(1.4)	(2.6)	(4.0)	(7.7)	(3.9)
Adjusted EBITDAX	$ 1,197.2	$ 473.5	$ 911.8	$ 1,635.3	$ 3,886.9	$ 3,673.1
Ratio of EBITDA to interest expense(A)	4.1	4.5	11.9	7.6	24.4	25.1

(A)

The ratio of EBITDA to interest expense is calculated by dividing EBITDA by the gross interest expense for the period before reduction for interest capitalized to development projects.

(4) We have computed the ratio of earnings to fixed charges by dividing earnings by fixed charges. For this purpose, earnings consist of income from continuing operations before income taxes adjusted for (1) fixed charges, (2) undistributed earnings of companies accounted for by the equity method, (3) capitalized interest, (4) amortization of capitalized interest and (5) interest portion of rentals. Fixed charges consist of interest and amortization of debt discount and expense, whether capitalized or expensed, and that portion of rental expense determined to be representative of the interest factor.

(5) Our earnings for the last twelve months ended June 30, 2016 and the six months ended June 30, 2016 and 2015 were inadequate to cover fixed charges by $3,432.7 million, $389.5 million and $215.1 million, respectively. Our earnings for the year ended December 31, 2015 were inadequate to cover fixed charges by $3,258.2 million.

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Summary historical operating data

We have provided in the table below our summary operating data for the six months ended June 30, 2016 and 2015 and each of the years in the three-year period ended December 31, 2015.

	Six Months Ended June 30,		Year Ended December 31,		
	2016	2015	2015	2014	2013
Exploration and Production:					
Net crude oil and condensates production barrels per day:					
United States	51,881	61,002	61,119	59,900	45,523
Canada conventional	11,319	14,088	12,877	16,216	18,281
Canada synthetic oil(1)	9,326	11,394	11,699	11,997	12,886
Malaysia(2)	38,709	44,294	40,705	54,295	53,131
Republic of Congo					1,046
Continuing operations	111,235	130,778	126,400	142,408	130,867
Discontinued operations					648
Total	111,235	130,778	126,400	142,408	131,515
Net natural gas liquids production barrels per day:					
United States	8,335	9,412	9,556	8,374	2,864
Canada	88	14	10	25	64
Malaysia(2)	635	668	668	840	635
Total	9,058	10,094	10,234	9,239	3,563
Net natural gas sold thousands of cubic feet per day:					
United States	57,297	94,593	87,372	88,471	53,212
Canada	207,288	193,133	196,774	156,478	175,449
Malaysia(2) Sarawak	97,155	111,431	121,650	168,712	164,671
Block K	12,124	25,804	21,818	32,295	29,699
Continuing operations	373,864	424,961	427,614	445,956	423,031
Discontinued operations					815
Total	373,864	424,961	427,614	445,956	423,846
Net hydrocarbon production equivalent barrels per day(3)	182,604	211,699	207,903	225,973	205,719
Estimated net hydrocarbon reserves million equivalent barrels(4)	N/A	N/A	774.0	756.5	687.9
Reserve life years(4, 5)	N/A	N/A	10.2	9.2	9.2

(1) Our production of synthetic oil was attributable to our 5% interest in Syncrude. We completed the sale of our interest in Syncrude to Suncor Energy Inc. in June 2016, and do not currently own any proved reserves of synthetic oil.

(2)

We sold a 20% interest in Malaysia properties on December 18, 2014 and sold an additional 10% interest on January 29, 2015. This table includes volumes for these sold interests through the date of disposition.

(3) 6,000 cubic feet of natural gas equals one equivalent barrel.

(4) Not reported on a quarterly basis.

(5) Total net proved hydrocarbon reserves at the end of the respective period divided by net hydrocarbon production for the year.

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Production-related expenses for continuing exploration and production operations during the last three years are shown in the following table:

	Year Ended December 31,		
	2015	2014	2013
(Millions of dollars)			
Lease operating expense	832.3	1,089.9	1,252.9
Severance and ad valorem taxes	65.8	107.2	87.3
Depreciation, depletion and amortization	1,607.9	1,897.5	1,543.6
Total	2,506.0	3,094.6	2,883.8

Cost per equivalent barrel sold for these production-related expenses are shown by geographical area in the following table:

	Year Ended December 31,		
	2015	2014	2013
(Millions of dollars)			
United States Eagle Ford Shale:			
Lease operating expense	10.27	11.25	11.15
Severance and ad valorem taxes	2.50	4.64	5.39
Depreciation, depletion and amortization (DD&A) expense	26.71	27.87	30.48
United States Gulf of Mexico:			
Lease operating expense	9.42	11.73	17.28
DD&A expense	22.60	27.47	21.32
Canada Conventional operations:			
Lease operating expense	6.18	10.37	10.50
Severance and ad valorem taxes	0.29	0.36	0.29
DD&A expense	12.74	17.00	18.58
Canada Synthetic oil operations(1):			
Lease operating expense	38.88	53.39	47.47
Severance and ad valorem taxes	1.20	1.16	1.04
DD&A expense	11.90	12.32	11.79
Malaysia Sarawak:			
Lease operating expense	7.82	7.91	9.43
DD&A expense	18.78	20.30	14.01
Malaysia Block K:			
Lease operating expense	13.20	15.04	14.30
DD&A expense	26.25	26.79	22.21
Total oil and gas operations:			
Lease operating expense	10.87	13.31	16.66
Severance and ad valorem taxes	0.86	1.31	1.16
Depreciation, depletion and amortization (DD&A) expense	21.00	23.16	20.53

(1) Our production of synthetic oil was attributable to our 5% interest in Syncrude. We completed the sale of our interest in Syncrude to Suncor Energy Inc. in June 2016, and do not currently own any proved reserves of synthetic oil.

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Summary reserve data

We have provided in the table below summary data with respect to our estimated proved developed and undeveloped reserves of oil and natural gas as of December 31, 2015 and 2014. Except as noted below, all information in this table relating to oil and natural gas reserves has been based upon our estimates and reflects our net interest after royalties.

Estimates of the proved reserves, future production and income attributable to our leasehold properties located in the Eagle Ford Shale in south Texas in the United States as of December 31, 2015, which represented approximately 41% of our total proved reserves (excluding synthetic oil) as of December 31, 2015 are confirmed in the audit report prepared by Ryder Scott Company, L.P., independent petroleum engineers, which has been incorporated by reference herein from our Current Report on Form 8-K filed on August 10, 2016.

	As of December 31,	
	2015	**2014**
Proved Developed and Undeveloped Reserves:		
Proved developed and undeveloped oil reserves millions of barrels:		
Crude oil and condensates:		
United States	238.9	204.9
Canada conventional	27.9	37.4
Canada synthetic oil (1)	114.8	105.6
Malaysia	74.6	93.9
Natural gas liquids	36.4	30.6
Total proved developed and undeveloped oil reserves	492.6	472.4
Proved developed and undeveloped natural gas reserves billions of cubic feet:		
United States	232.4	226.3
Canada	909.6	842.8
Malaysia	546.8	635.6
Total proved developed and undeveloped natural gas reserves	1,688.8	1,704.7
Total estimated net proved developed and undeveloped hydrocarbon reserves millions of equivalent barrels(2)	774.0	756.5
PV-10 value(3)	$ 4,281.4	$ 12,895.6
Standardized measure(4)	$ 3,859.1	$ 9,905,2

(1) Our proved reserves of synthetic oil as of December 31, 2014 and 2015 were attributable to our 5% interest in Syncrude. We completed the sale of our interest in Syncrude to Suncor Energy Inc. in June 2016, and do not currently own any proved reserves of synthetic oil.

(2) 6,000 cubic feet of natural gas equals one equivalent barrel.

(3) Represents present value, discounted at 10% per annum, of estimated future net revenue before income tax of our estimated proved reserves. The estimated future net revenues set forth above were determined by using reserve quantities of proved reserves and the periods in which they are expected to be developed and produced based on certain prevailing economic conditions. The estimated future production in our reserve report as of December 31, 2015 is priced based on the 12-month unweighted arithmetic average of the first-day of-the month price for each month within such period, unless such prices were defined by contractual arrangements, as required by SEC regulations.

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PV-10 is a non-GAAP measure because it excludes income tax effects. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. PV-10 is not a measure of financial or operating performance under United States generally accepted accounting principles, or GAAP. PV-10 should not be considered as an alternative to the standardized measure as defined under GAAP. We have included a reconciliation of PV-10 to standardized measure of discounted future net cash flows, the most directly comparable GAAP measure. The following table reconciles the standardized measure of future net cash flows to the PV-10 value:

	As of December 31,	
	2015	**2014**
Standardized measure of discounted future net cash flows	$ 3,859.1	9,905.2
Income taxes	$ 422.3	2,990.4
PV-10 value	$ 4,281.4	12,895.6

(4) The standardized measure represents the calculation of future net cash flows using a 10% annual discount factor, an unweighted average of oil and natural gas prices in effect at the beginning of each month of the year, and year-end costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs and governmental policies do not remain static; appropriate discount rates may vary; and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

The following table sets forth our standardized measure and PV-10 as of December 31, 2015 for each geographic location in which we own proved reserves:

Reserve Category: (Millions of dollars)	**Proved Reserves as of December 31, 2015**
United States:	
Standardized measure	2,028.3
Income taxes	31.1
PV-10 value(1)	2,059.4
Canada conventional(2):	
Standardized measure	375.2
Income taxes	169.6
PV-10 value(1)	544.8

Malaysia:	
Standardized measure	1,118.5
Income taxes	157.4
PV-10 value(1)	1,275.9

(1) Represents present value, discounted at 10% per annum, of estimated future net revenue before income tax of our estimated proved reserves. The estimated future net revenues set forth above were determined by using reserve quantities of proved reserves and the periods in which they are expected to be developed and produced based on certain prevailing economic conditions. The estimated future production in our reserve report as of December 31, 2015 is priced based on the 12-month unweighted arithmetic average of the first-day of-the month price for each month within such period, unless such prices were defined by contractual arrangements, as required by SEC regulations.

PV-10 is a non-GAAP measure because it excludes income tax effects. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. PV-10 is not a measure of financial or operating performance under United States generally accepted accounting principles, or GAAP. PV-10 should not be considered as an alternative to the standardized measure as defined under GAAP. We have included a reconciliation of PV-10 to standardized measure of discounted future net cash flows, the most directly comparable GAAP measure, in the table above.

The standardized measure represents the present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, abandonment, production and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

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(2) Excludes synthetic oil. Our proved reserves of synthetic oil as of December 31, 2015 were attributable to our equity interest in Syncrude. We completed the sale of our interest in Syncrude to Suncor Energy Inc. in June 2016, and do not currently own any proved reserves of synthetic oil.

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Risk factors

Investing in the notes involves risks. You should carefully consider all the information set forth in this prospectus supplement, the accompanying prospectus and the documents incorporated by reference herein and therein before deciding to invest in the notes. In particular, we urge you to carefully consider the risk factors set forth below as well as those under the heading Risk Factors in our Annual Report on Form 10-K for fiscal year ended December 31, 2015.

Risks relating to our business

Current low oil prices may adversely affect the Company s operations in several ways in the future.

As noted elsewhere in this prospectus supplement, crude oil prices were significantly weaker in 2015 than in prior years. Oil prices have continued to slide into early 2016. These low oil prices have adversely affected the company in several ways, and could continue to do so in 2016 as noted below:

- The lower sales value for the Company s oil production has hurt cash flows and net income. The current low commodity prices are expected to continue this trend into 2016.

- Lower cash flows have caused the Company to reduce its capital expenditure program, thereby potentially hampering its ability to grow production and add proved reserves. The Company may be forced to continue to reduce its capital expenditures to balance its cash positions going forward.

- Lower expected future oil prices led to significant impairment expenses in 2015. Further reductions for future oil prices in 2016 could lead to more impairment charges, some of which could be significant.

- Low oil prices could lead to reductions in the Company s proved reserves in 2016. Low prices could make certain of the Company s proved reserves uneconomic, which in turn could lead to removal of certain of the Company s 2015 year-end reported proved oil reserves in future periods. These reserve reductions could be significant.

- Major credit rating agencies have initiated or completed credit reviews of many oil and gas companies, including Murphy Oil. The low oil prices have hurt oil companies financial metrics, and the credit rating agencies tend to lower credit ratings during such periods of low commodity prices. In addition, banks and other suppliers of financing capital may reduce their lending limits to oil companies due to weak oil prices. At December 31, 2015, Murphy s long-term debt was rated BBB with a negative outlook by Standard and Poor s (S&P), BBB- with a negative outlook by Fitch Ratings (Fitch), and Baa3 with a negative outlook by Moody s Investor Services (Moody s). In February 2016, S&P, Fitch, and Moody s each downgraded the Company s credit rating on its outstanding notes. The Company s long-term debt ratings are currently BBB- with stable outlook by S&P, BB+ with stable outlook by Fitch, and B1 with negative outlook by Moody s. Fitch s and Moody s actions reduced the Company s credit rating to below investment grade status. These downgrades could adversely affect our cost of capital and our ability to raise debt in public markets in future periods.

Certain of these effects are further discussed in risk factors that follow.

Murphy Oil s businesses operate in highly competitive environments, which could adversely affect it in many ways, including its profitability, its ability to grow, and its ability to manage its businesses.

Murphy operates in the oil and gas industry and experiences intense competition from other oil and gas companies, which include state-owned foreign oil companies, major integrated oil companies, and independent producers of oil and natural gas. Virtually all of the state-owned and major integrated oil companies and many of the independent producers that compete with the Company have substantially greater resources than

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Murphy. In addition, the oil industry as a whole competes with other industries in supplying energy requirements around the world. Murphy competes, among other things, for valuable acreage positions, exploration licenses, drilling equipment and human resources.

If Murphy cannot replace its oil and natural gas reserves, it may not be able to sustain or grow its business.

Murphy continually depletes its oil and natural gas reserves as production occurs. In order to sustain and grow its business, the Company must successfully replace the crude oil and natural gas it produces with additional reserves. Therefore, it must create and maintain a portfolio of good prospects for future reserves additions and production by obtaining rights to explore for, develop and produce hydrocarbons in promising areas. In addition, it must find, develop and produce and/or purchase reserves at a competitive cost structure to be successful in the long-term. Murphy s ability to operate profitably in the exploration and production segments of its business, therefore, is dependent on its ability to find, develop and produce and/or purchase oil and natural gas reserves at costs that are less than the realized sales price for these products and at costs competitive with competing companies in the industry.

Murphy s proved reserves are based on the professional judgment of its engineers and may be subject to revision.

Proved reserves of crude oil, natural gas liquids (NGL) and natural gas included elsewhere and incorporated by reference in this prospectus supplement and the accompanying prospectus have been prepared by qualified Company personnel or qualified independent engineers based on an unweighted average of crude oil, NGL and natural gas prices in effect at the beginning of each month of the respective year as well as other conditions and information available at the time the estimates were prepared. Estimation of reserves is a subjective process that involves professional judgment by engineers about volumes to be recovered in future periods from underground oil and natural gas reservoirs. Estimates of economically recoverable crude oil, NGL and natural gas reserves and future net cash flows depend upon a number of variable factors and assumptions, and consequently, different engineers could arrive at different estimates of reserves and future net cash flows based on the same available data and using industry accepted engineering practices and scientific methods. Under existing SEC rules, reported proved reserves must be reasonably certain of recovery in future periods.

Murphy s actual future oil and natural gas production may vary substantially from its reported quantity of proved reserves due to a number of factors, including:

- Oil and natural gas prices which are materially different than prices used to compute proved reserves

- Operating and/or capital costs which are materially different than those assumed to compute proved reserves

- Future reservoir performance which is materially different from models used to compute proved reserves, and

- Governmental regulations or actions which materially change operations of a field.

The Company s proved undeveloped reserves represent significant portions of total proved reserves. As of December 31, 2015, approximately 28% of the Company s crude oil proved reserves, 41% of natural gas liquids proved reserves and 54% of natural gas proved reserves are undeveloped. The ability of the Company to reclassify these undeveloped proved reserves to the proved developed classification is generally dependent on the successful completion of one or more operations, which might include further development drilling, construction of facilities or pipelines, and well workovers.

The discounted future net revenues from our proved reserves as reported and incorporated by reference in this prospectus supplement and the accompanying prospectus should not be considered as the market value of the reserves attributable to our properties. As required by GAAP, the estimated discounted future net revenues from our proved reserves are based on an unweighted average of the oil and natural gas prices in effect at the beginning of each month during the year. Actual future prices and costs may be materially higher or lower than those used in the reserves computations.

In addition, the 10 percent discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under GAAP is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the crude oil and natural gas business in general.

Volatility in the global prices of crude oil, natural gas liquids and natural gas significantly affects the Company s operating results.

Among the most significant variables affecting the Company s results of operations are the sales prices for crude oil and natural gas that it produces. West Texas Intermediate (WTI) crude oil prices averaged about $49 per barrel in 2015, compared to $93 per barrel in 2014 and $98 per barrel in 2013. The closing price for WTI at the end of 2015 was approximately $37 per barrel. As demonstrated by the significant decline in WTI crude oil prices in late 2014 and 2015, prices can be quite volatile. The average NYMEX natural gas sales price was $2.61 per thousand cubic feet (MCF) in 2015, down from $4.34 per MCF in 2014 and $3.73 per MCF in 2013. The closing price for NYMEX natural gas trades as of December 31, 2015, was $2.34 per MCF. As demonstrated in 2013 through 2015, the sales prices for crude oil and natural gas can be significantly different in U.S. markets compared to markets in foreign locations. A small percentage of the Company s crude oil production is heavy and more sour than WTI quality crude; therefore, this crude oil usually sells at a discount to WTI and other light and sweet crude oils. In addition, the sales prices for heavy and sour crude oils do not always move in relation to price changes for WTI and lighter/sweeter crude oils. Certain crude oils produced by the Company, including certain U.S. and Canadian crude oils and all crude oil produced in Malaysia, generally price off of oil indices other than WTI, and these indices are influenced by different supply and demand forces than those that affect the U.S. WTI prices. The most common crude oil indices used to price the Company s crude include Louisiana Light Sweet (LLS), Brent and Malaysian crude oil indices. Certain natural gas production offshore Sarawak have been sold in recent years at a premium to average North American natural gas prices due to pricing structures built into the sales contracts. Associated natural gas produced at fields in Block K offshore Sabah are sold at heavily discounted prices compared to North American gas prices as stipulated in the sales contract. The Company cannot predict how changes in the sales prices of oil and natural gas will affect its results of operations in future periods. The Company often seeks to hedge a portion of its exposure to the effects of changing prices of crude oil and natural gas by purchasing forwards, swaps and other forms of derivative contracts.

Exploration drilling results can significantly affect the Company s operating results.

The Company drills exploratory wells each year which subjects its exploration and production operating results to significant exposure to dry holes expense, which may have adverse effects on, and create volatility for, the Company s results of operations. In 2015, wildcat wells were primarily drilled offshore Australia, Malaysia and in the Gulf of Mexico. The Company s 2016 planned exploratory drilling program includes only commitment wells in Block SK 314A in Malaysia and Blocks 11-21/11 and 15-1/05 in Vietnam.

Potential federal or state regulations could increase the Company s costs and/or restrict operating methods, which could adversely affect its production levels.

The Company uses a technique known as hydraulic fracturing whereby water, sand and certain chemicals are injected into deep oil and gas bearing reservoirs in North America. This process creates fractures in the rock formation within the reservoir which enables oil and natural gas to migrate to the wellbore. The Company primarily uses this technique in the Eagle Ford Shale in South Texas and in Western Canada. This practice is generally regulated by the states, but at times the U.S. has proposed additional regulation under the Safe

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Drinking Water Act. In June 2011, the State of Texas adopted a law requiring public disclosure of certain information regarding the components used in the hydraulic fracturing process. The Provinces of British Columbia and Alberta have also issued regulations related to hydraulic fracturing activities under their jurisdictions. It is possible that the states, the U.S., Canadian provinces and certain municipalities adopt further laws or regulations which could render the process unlawful, less effective or drive up its costs. If any such action is taken in the future, the Company s production levels could be adversely affected or its costs of drilling and completion could be increased.

In April 2016, the U.S. Department of the Interior s Bureau of Safety and Environmental Enforcement (BSEE) announced final rules providing for broad regulatory changes related to well design, well control, casing, cementing, real-time monitoring, and subsea containment, among other items known broadly as the Well Control Rule. The rules will require compliance over the next several years and could significantly increase the Company s future costs in the U.S. Gulf of Mexico.

Hydraulic fracturing exposes the Company to operational and regulatory risks and third party claims.

Hydraulic fracturing operations subject the Company to operational risks inherent in the drilling and production of oil and natural gas. These risks include underground migration or surface spillage due to releases of oil, natural gas, formation water or well fluids, as well as any related surface or ground water contamination, including from petroleum constituents or hydraulic fracturing chemical additives. Ineffective containment of surface spillage and surface or ground water contamination resulting from hydraulic fracturing operations, including from petroleum constituents or hydraulic fracturing chemical additives, could result in environmental pollution, remediation expenses and third party claims alleging damages, which could adversely affect the Company s financial condition and results of operations. In addition, hydraulic fracturing requires significant quantities of water. Any diminished access to water for use in the process could curtail the Company s operations or otherwise result in operational delays or increased costs.

Capital financing may not always be available to fund Murphy s activities.

Murphy usually must spend and risk a significant amount of capital to find and develop reserves before revenue is generated from production. Although most capital needs are funded from operating cash flow, the timing of cash flows from operations and capital funding needs may not always coincide, and the levels of cash flow generated by operations may not fully cover capital funding requirements, especially in periods of low commodity prices such as those experienced in 2015 and early 2016. Therefore, the Company maintains financing arrangements with lending institutions to meet certain funding needs. The Company must periodically renew these financing arrangements based on foreseeable financing needs or as they expire. The Company s primary bank financing facility has a capacity of $2.0 billion and matures in May 2017. Concurrently with or prior to the consummation of this offering, the Company expects to enter into a new revolving credit facility, with aggregate commitments of $1.2 billion and a maturity in 2019. Consummation of this offering is a condition precedent to the new revolving credit facility. In addition, the Company intends to amend its existing revolving credit facility to reduce the commitments of the exiting lenders that have committed to the new revolving credit facility and allow for the incurrence of the new revolving credit facility. There is the possibility that financing arrangements may not always be available at sufficient levels required to fund the Company s activities in future periods. On February 18, 2016, Moody s Investor Services downgraded the Company s senior unsecured notes to a B1 rating, effectively reducing the Company s credit to below investment grade status. The ability of the Company to obtain future debt financing may be adversely affected by this credit rating downgrade. Also, in February, Fitch Rating downgraded the Company s notes to below investment grade. These downgrades could adversely affect our cost of capital and our ability to raise debt as needed in public markets in future periods. Additionally, in order to obtain debt financing in future years, the Company may have to provide more security to its lenders.

Additionally, should low oil and gas prices continue in 2016 and 2017, the ability of the Company to repay or refinance its $550 million note that matures in December 2017 may be adversely impacted. The Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through October 2018. Although not considered likely, the Company may not be able in the future to sell notes in the marketplace.

Murphy has limited or virtually no control over several factors that could adversely affect the Company.

The ability of the Company to successfully manage development and operating costs is important because virtually all of the products it sells are energy commodities such as crude oil, natural gas liquids and natural gas, for which the Company has little or no influence on the sales prices or regional and worldwide consumer demand for these products. Changes in commodity prices also impact the volume of production attributed to the Company under production sharing contracts in Malaysia. Economic slowdowns, such as those experienced in 2008 and 2009, had a detrimental effect on the worldwide demand for these energy commodities, which effectively led to reduced prices for oil and natural gas for a period of time. An oversupply of crude oil in 2015 led to a severe decline in worldwide oil prices. Lower prices for crude oil and natural gas inevitably lead to lower earnings for the Company. The Company also often experiences pressure on its operating and capital expenditures in periods of strong crude oil and natural gas prices because an increase in exploration and production activities due to high oil and gas sales prices generally leads to higher demand for, and consequently higher costs for, goods and services in the oil and gas industry. The current low crude oil price environment in 2015 and early 2016 has caused the Company to reduce discretionary drilling programs, which in turn, hurts the Company s future production levels and future cash flow generated from operations.

Many of the Company s major oil and natural gas producing properties are operated by others. Therefore, Murphy does not fully control all activities at certain of its significant revenue generating properties. During 2015, approximately 15% of the Company s total production was at fields operated by others, while at December 31, 2015, approximately 22% of the Company s total proved reserves were at fields operated by others.

Murphy s operations and earnings have been and will continue to be affected by worldwide political developments.

Many governments, including those that are members of the Organization of Petroleum Exporting Countries (OPEC), unilaterally intervene at times in the orderly market of crude oil and natural gas produced in their countries through such actions as setting prices, determining rates of production, and controlling who may buy and sell the production. As of December 31, 2015, approximately 21% of the Company s proved reserves, as defined by the U.S. Securities and Exchange Commission, were located in countries other than the U.S. and Canada. Certain of the reserves held outside these two countries could be considered to have more political risk. In addition, prices and availability of crude oil, natural gas and refined products could be influenced by political unrest and by various governmental policies to restrict or increase petroleum usage and supply. Other governmental actions that could affect Murphy s operations and earnings include expropriation, tax changes, royalty increases, redefinition of international boundaries, preferential and discriminatory awarding of oil and gas leases, restrictions on drilling and/or production, restraints and controls on imports and exports, safety, and relationships between employers and employees. Governments could also initiate regulations concerning matters such as currency fluctuations, protection and remediation of the environment, and concerns over the possibility of global warming or other climate change being affected by human activity including the production and use of hydrocarbon energy. Additionally, because of the numerous countries in which the Company operates, certain other risks exist, including the application of the U.S. Foreign Corrupt Practices Act, the Canada Corruption of Foreign Officials Act, the Malaysia Anti-Corruption Commission Act, the U.K. Bribery Act, and similar anti-corruption compliance statutes. Because these and other factors too numerous to list are subject to changes caused by governmental and political considerations and are often made in response to

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changing internal and worldwide economic conditions and to actions of other governments or specific events, it is not practical to attempt to predict the effects of such factors on Murphy s future operations and earnings.

Murphy s business is subject to operational hazards, security risks and risks normally associated with the exploration for and production of oil and natural gas.

The Company operates in urban and remote, and often inhospitable, areas around the world. The occurrence of an event, including but not limited to acts of nature such as hurricanes, floods, earthquakes and other forms of severe weather, and mechanical equipment failures, industrial accidents, fires, explosions, acts of war, civil unrest, piracy and acts of terrorism could result in the loss of hydrocarbons and associated revenues, environmental pollution or contamination, personal injury, including death, and property damages for which the Company could be deemed to be liable, and which could subject the Company to substantial fines and/or claims for punitive damages.

The location of many of Murphy s key assets causes the Company to be vulnerable to severe weather, including hurricanes and tropical storms. A number of significant oil and natural gas fields lie in offshore waters around the world. Probably the most vulnerable of the Company s offshore fields are in the U.S. Gulf of Mexico, where severe hurricanes and tropical storms have often led to shutdowns and damages. The U.S. hurricane season runs from June through November. Although the Company maintains insurance for such risks as described elsewhere in this prospectus supplement, due to policy deductibles and possible coverage limits, weather-related risks are not fully insured.

In addition, the Company has risks associated with cybersecurity attacks. Although the Company maintains processes and systems to monitor and avoid damages from security threats, there can be no assurance that such processes and systems will successfully avert such security breaches. A successful breach could lead to system disruptions, loss of data or unauthorized release of highly sensitive data. This could lead to property or environmental damages and could have an adverse effect on the Company s revenues and costs.

Murphy s insurance may not be adequate to offset costs associated with certain events and there can be no assurance that insurance coverage will continue to be available in the future on terms that justify its purchase.

Murphy maintains insurance against certain, but not all, hazards that could arise from its operations. The Company maintains liability insurance sufficient to cover its share of gross insured claim costs up to approximately $500 million per occurrence and in the annual aggregate. Generally, this insurance covers various types of third party claims related to personal injury, death and property damage, including claims arising from sudden and accidental pollution events. The Company also maintains insurance coverage with an additional limit of $400 million per occurrence ($850 million for Gulf of Mexico operations not related to a named windstorm), all or part of which could be applicable to certain sudden and accidental pollution events. These policies have deductibles ranging from $10 to $25 million. The occurrence of an event that is not insured or not fully insured could have a material adverse effect on the Company s financial condition and results of operations in the future.

Lawsuits against Murphy and its subsidiaries could adversely affect its operating results.

The Company is involved in numerous lawsuits seeking cash settlements for alleged personal injuries, property damages and other business-related matters. Certain of these lawsuits will take many years to resolve through court proceedings or negotiated settlements. None of these lawsuits are considered individually material or aggregate to a material amount in the opinion of management.

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The Company is exposed to credit risks associated with sales of certain of its products to third parties.

Although Murphy limits its credit risk by selling its products to numerous entities worldwide, it still, at times, carries substantial credit risk from its customers. For certain oil and gas properties operated by the Company, other companies which own partial interests may not be able to meet their financial obligation to pay for their share of capital and operating costs as they come due. The inability of a purchaser of the Company s oil or natural gas or a partner of the Company to meet their respective payment obligations to the Company could have an adverse effect on Murphy s future earnings and cash flows.

Murphy s operations could be adversely affected by changes in foreign currency conversion rates.

The Company s worldwide operational scope exposes it to risks associated with foreign currencies. Most of the Company s business is transacted in U.S. dollars, therefore, the Company and most of its subsidiaries are U.S. dollar functional entities for accounting purposes. However, the Canadian dollar is the functional currency for all Canadian operations and the British pound is the functional currency for most remaining U.K. discontinued operations. In certain countries, such as Canada, Malaysia and the United Kingdom, significant levels of transactions occur in currencies other than the functional currency. In Malaysia, such transactions include tax payments, while in Canada, certain crude oil sales are priced in U.S. dollars. This exposure to currencies other than the functional currency can lead to significant impacts on consolidated financial results. Exposures associated with current and deferred income tax liability balances in Malaysia are generally not hedged. A strengthening of the Malaysian ringgit against the U.S. dollar would be expected to lead to currency losses in consolidated operations; gains would be expected if the ringgit weakens versus the dollar. Foreign exchange exposures between the U.S. dollar and the British pound are not hedged. The Company would generally expect to incur currency losses when the U.S. dollar strengthens against the British pound and would conversely expect currency gains when the U.S. dollar weakens against the pound. In Canada, currency risk is often managed by selling forward U.S. dollars to match the collection dates for crude oil sold in that currency. See Note L in the audited consolidated financial statements included elsewhere and incorporated by reference in this prospectus supplement and the accompanying prospectus for additional information on derivative contracts.

The costs and funding requirements related to the Company s retirement plans are affected by several factors.

The costs and funding requirements related to the Company s retirement plans are affected by several factors. A number of actuarial assumptions impact funding requirements for the Company s retirement plans. The most significant of these assumptions include return on assets, long-term interest rates and mortality. If the actual results for the plans vary significantly from the actuarial assumptions used, or if laws regulating such retirement plans are changed, Murphy could be required to make more significant funding payments to one or more of its retirement plans in the future and/or it could be required to record a larger liability for future obligations in its consolidated balance sheet.

Risks relating to the notes

The notes are structurally subordinated to all liabilities of our subsidiaries and all liabilities guaranteed by our subsidiaries.

The notes are structurally subordinated to all liabilities of our subsidiaries and all liabilities guaranteed by our subsidiaries, including without limitation, their debt and trade payables and our revolving credit facility. As of June 30, 2016, after giving effect to our new revolving credit facility, the amendment of our existing revolving credit facility and the guarantee of our obligations under our existing revolving credit facility by certain of our material subsidiaries, which will not guarantee the notes, we would have had approximately $178.6 million of issued and undrawn letters of credit outstanding, all of which would have been structurally senior to the notes. Additionally, as of June 30, 2016 our subsidiaries had approximately $798.1 million in indebtedness, trade payables and other accrued current liabilities outstanding, all of which would rank structurally senior to the notes. None of our subsidiaries has guaranteed or otherwise become obligated with respect to the notes. Our right to receive assets from any of our subsidiaries upon its liquidation or reorganization, and the right of the holders of the notes to participate in those assets, is structurally subordinated to claims of that subsidiary s creditors. We and our subsidiaries will be permitted under the terms of the indenture governing the notes to incur certain additional indebtedness or otherwise enter into agreements that may restrict or prohibit subsidiaries of ours from the making of distributions, the payment of dividends or the making of loans to us. Even if we were a creditor of any of our subsidiaries, our rights as a creditor would be subordinate to any security interest in the assets of that subsidiary and any debt of that subsidiary senior to that held by us, and our rights could otherwise be subordinated to the rights of other creditors of that subsidiary. Furthermore, we are a holding company and currently conduct substantially all of our operations through our subsidiaries, and our subsidiaries generate substantially all of our operating income and cash flow. As a result, distributions or advances from our subsidiaries are the principal source of the funds we use to meet our debt service obligations. None of our subsidiaries is under any obligation to make payments to us, and any payments to us would depend on the earnings or financial condition of our subsidiaries and various business considerations. Contractual or other legal restrictions may also limit our subsidiaries ability to pay dividends or make distributions, loans or advances to us. For these reasons, we may not have access to any assets or cash flows of our subsidiaries to make interest and principal payments on the notes.

Changes in our credit ratings may adversely affect your investment in the notes.

The credit ratings of our indebtedness are an assessment by rating agencies of our ability to pay our debts when due. These ratings are not recommendations to purchase, hold or sell the notes, inasmuch as the ratings do not comment as to market price or suitability for a particular investor, are limited in scope, and do not address all material risks relating to an investment in the notes, but rather reflect only the view of each rating agency at the time the rating is issued. The ratings are based on current information furnished to the ratings agencies by us and information obtained by the ratings agencies from other sources. An explanation of the significance of such rating may be obtained from such rating agency. There can be no assurance that such credit ratings will remain in effect for any given period of time or that such ratings will not be lowered, suspended or withdrawn entirely by the rating agencies, if, in each rating agency s judgment, circumstances so warrant. Actual or anticipated changes or downgrades in our credit ratings, including any announcement that our ratings are under review for a downgrade, could affect the market value and liquidity of the notes and increase our borrowing costs.

Despite our current level of indebtedness, we and our subsidiaries may still be able to incur substantially more debt.

We and our subsidiaries may be able to incur substantial additional indebtedness, including additional notes and secured indebtedness, in the future. The indenture governing the notes will not prohibit us from incurring additional indebtedness that is not secured or guaranteed by our subsidiaries. Further, the indenture governing the notes will not fully prohibit our subsidiaries from incurring additional indebtedness or prohibit us or our subsidiaries from incurring secured indebtedness, and any limitations will be subject to a number of significant qualifications and exceptions. Additionally, the indenture governing the notes will not prevent us or our subsidiaries from incurring obligations that do not constitute indebtedness under the indenture.

The notes will be effectively junior to all of our secured indebtedness unless they are entitled to be equally and ratably secured.

The notes will be our senior unsecured obligations and will rank equally with all our other senior unsecured indebtedness. The notes will be effectively subordinated to any secured debt we may incur in the future to the

extent of the value of the assets securing such debt. Although the indenture governing the notes will limit our ability to incur secured debt, any limitations will be subject to a number of significant qualifications and exceptions. If we default on the notes, become bankrupt, liquidate or reorganize, any secured creditors could use our assets securing their debt to satisfy their secured debt before you would receive any payment on the notes. If the value of the collateral is not sufficient to pay any secured debt in full, our secured creditors would share the value of our other assets, if any, with you and the holders of other claims against us that rank equally with the notes. As of June 30, 2016, we had approximately $2.44 billion of consolidated indebtedness outstanding, none of which was secured. Under the terns of our new revolving credit facility, if the total leverage ratio falls below a ratio to be agreed, we will be obligated to provide, subject to certain exceptions, a pledge of substantially all of our tangible and intangible assets, as well as the tangible and intangible assets of the guarantors thereunder.

We may be unable to purchase the notes upon a change of control triggering event.

The terms of the notes will require us to make an offer to repurchase the notes upon the occurrence of a change of control triggering event at a purchase price equal to 101% of the principal amount of the notes, plus accrued and unpaid interest to the date of the repurchase. The occurrence of a change of control triggering event would cause an event of default under our revolving credit facility and therefore could cause us to have to repay amounts outstanding thereunder, and any financing arrangements we may enter into in the future may also require repayment of amounts outstanding in the event of a change of control triggering event and therefore limit our ability to fund the repurchase of your notes pursuant to the change of control offer. It is possible that we will not have sufficient funds, or be able to arrange for additional financing, at the time of the change of control triggering event to make the required repurchase of notes. If we have insufficient funds to repurchase all notes that holders tender for purchase pursuant to the change of control offer, and we are unable to raise additional capital, an event of default would occur under the indenture. An event of default could cause any other debt that we may have at that time to become automatically due, further exacerbating our financial condition and diminishing the value and liquidity of the notes. We cannot assure you that additional capital would be available to us on acceptable terms, or at all. See Description of the notes Repurchase upon a change of control triggering event.

Your ability to transfer the notes may be limited by the absence of an active trading market, and there is no assurance that any active trading market will develop for the notes.

The notes are a new issue of securities for which there is no established trading market. The underwriters have advised us that they intend to make a market in the notes, as permitted by applicable laws and regulations; however, the underwriters are not obligated to make a market in the notes and they may discontinue their market-making activities at any time without notice. Therefore, an active market for the notes may not develop or, if developed, may not continue. The liquidity of any market for the notes will depend upon, among other things, the number of holders of the notes, our performance, the market for similar securities, the interest of securities dealers in making a market in the notes and other factors. If a market develops, the notes could trade at prices that may be lower than the initial offering prices of the notes.

Use of proceeds

We expect the net proceeds from this offering of notes to be approximately $491.7 million, after deducting underwriting discounts and other estimated expenses of the offering. We intend to use the net proceeds of this offering for general corporate purposes, which may include repayment, repurchase or redemption of our 2.5% notes due 2017. See Underwriting beginning on page S-100.

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Capitalization

We have provided in the table below our unaudited consolidated capitalization as of June 30, 2016, and as adjusted to give effect to the issuance of the notes offered hereby and the use of proceeds therefrom for general corporate purposes.

	As of June 30, 2016	
(unaudited) **(in thousands)**	**Actual**	**As Adjusted**
Cash and cash equivalents	$ 267,483	$ 759,183
Long-term debt:		
2.50% Notes, due 2017	550,000	550,000
4.00% Notes, due 2022	500,000	500,000
3.70% Notes, due 2022	600,000	600,000
% Notes, due 2024 offered hereby(1)		500,000
7.05% Notes, due 2029	250,000	250,000
5.125% Notes, due 2042	350,000	350,000
Notes payable to banks, 1.89% at June 30, 2016		
Unamortized discount on Notes payable	(17,174)	(17,174)
Revolving Credit Facility(2)		
Capital Lease Obligation	202,660	202,660
Total long-term debt (excluding current maturities)	$ 2,435,486	$ 2,935,486
Stockholders equity:		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued		
Common Stock, par $1.00, authorized 450,000,000 shares, issued 195,055,724 shares	195,056	195,056
Capital in excess of par value	914,236	914,236
Retained earnings	5,895,794	5,895,794
Accumulated other comprehensive income	(536,659)	(536,659)
Treasury stock, 22,856,616 shares of Common Stock , at cost	(1,296,734)	(1,296,734)
Total stockholders equity	$ 5,171,693	$ 5,171,693
Total capitalization (long-term debt and stockholders equity)	$ 7,607,179	$ 8,107,179

(1) Assumes the notes are issued at par.

(2) Currently, our revolving credit facility has commitments in an aggregate amount of $2.0 billion, none of which were drawn as of June 30, 2016. Upon consummation of the New Revolving Credit Facility, which will extend

the maturity of the facility by two years, to June 2019, we will reduce the aggregate commitments to $1.2 billion. Lenders that do not participate in the New Revolving Credit Facility will remain lenders under our existing revolving credit facility with aggregate commitments of $630 million, until its currently scheduled maturity.

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Management s discussion and analysis of financial condition and results of operations

Management s discussion and analysis is the Company s analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the combined financial statements and notes included in this prospectus supplement. It contains forward-looking statements including, without limitation, statements relating to the Company s plans, strategies, objectives, expectations and intentions. The words anticipate, estimate, believe, budget, continue, could, intend, may, plan, potential, predict, seek, should, will, would, expect, objective, projection, forecast, goal, guidance, outlook, effort, target and similar expressions identify forward-looking statements. The Company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the Company s disclosures under Forward-looking statements and Risk factors included elsewhere in this prospectus supplement.

Overview

Murphy Oil Corporation is a worldwide oil and gas exploration and production company. Significant Company operating and financial highlights during 2015 were as follows:

- Completed the sale of 10% of its interest in Malaysia assets for a price of $417.2 million. The Company recorded an after-tax gain of $218.8 million on the sale. Total proceeds received from the 30% sale over 2015 and 2014 totaled $1.87 billion after post closing adjustments.
- Produced 208,000 barrels of oil equivalent per day.
- Ended 2015 with proved reserves, totaling 774.0 million barrels of oil equivalent, and replaced proved reserves equal to 123% of production on a barrel of oil equivalent basis during the year, including the 10% Malaysia sell-down in 2015.
- Reduced lease operating expense per barrel oil equivalent by 18 percent year-over-year.
- Lowered G&A expense by approximately 16 percent year-over-year.
- Completed the sale of U.K. downstream operations.

The Company decommissioned the Milford Haven refinery units and completed the sale of its remaining downstream assets in the U.K. in the second quarter of 2015 for cash proceeds of $5.5 million. The Company has accounted for this U.K. downstream business as discontinued operations for all periods presented.

On August 30, 2013, the Company completed the separation of its former U.S. retail marketing business by distributing all common shares of this business to Murphy Oil s shareholders.

Both the U.S. and U.K. downstream businesses are reported as discontinued operations within the Company s consolidated financial statements. Additionally, the Company includes U.K. oil and gas operations, which were sold in a series of transactions in the first half of 2013, as discontinued operations.

Murphy s continuing operations generate revenue by producing crude oil, natural gas liquids (NGL) and natural gas in the United States, Canada and Malaysia and then selling these products to customers. The Company s revenue is highly affected by the prices of crude oil, natural gas and

NGL. In order to make a profit and generate cash in its exploration and production business, revenue generated from the sales of oil and natural gas produced must exceed the combined costs of producing these products, depreciation of capital expenditures, and expenses related to exploration, administration, and for capital borrowed from lending institutions and note holders.

Changes in the price of crude oil and natural gas have a significant impact on the profitability of the Company, especially the price of crude oil as oil represented 61% of total hydrocarbons produced on an energy equivalent basis (one barrel of crude oil equals six thousand cubic feet of natural gas) in 2015. In 2016, the Company s ratio of hydrocarbon production represented by oil is expected to be essentially the same as 2015. When oil-price linked natural gas in Malaysia is combined with oil production, the Company s 2016 total expected production is approximately 70% linked to the price of oil. If the prices for crude oil and natural gas remains weak in 2016 or beyond, this will have an unfavorable impact on the Company s operating profits. As described on page S-29, the Company has entered into fixed price derivative swap contracts in the United States that will reduce its exposure to changes in crude oil prices for approximately 42% of its 2016 U.S. oil production and holds forward delivery contracts that will reduce its exposure to changes in natural gas prices for approximately 28% of the natural gas it expects to produce in Western Canada in 2016.

During the first half of 2016, worldwide benchmark oil and natural gas prices have been significantly below average comparable benchmark prices during 2015. These lower oil and natural gas prices coupled with a property impairment in the 2016 period have led the Company to incur losses from operations in the first six months of 2016. Although the Company has been aggressively attacking its overall cost structure, a continuation of very low commodity prices would likely lead to further adverse effects on the Company s income and cash flow in future periods.

Oil prices and North American natural gas prices weakened in 2015 compared to the 2014 period. The sales price for a barrel of West Texas Intermediate (WTI) crude oil averaged $48.80 in 2015, $93.00 in 2014 and $98.00 in 2013. The sales price for a barrel of Platts Dated Brent crude oil declined to $52.46 per barrel in 2015, following averages of $99.00 per barrel and $108.66 per barrel in 2014 and 2013, respectively. Both the WTI index and Dated Brent experienced a 47% decrease in 2015. During 2015 the discount for WTI crude compared to Dated Brent narrowed compared to the two prior years. The WTI to Dated Brent discount was $3.66 per barrel during 2015, compared to $6.00 per barrel in 2014 and $10.61 per barrel in 2013. In early 2016, Dated Brent has been trading near par or at a slight discount to WTI. Worldwide oil prices began to weaken in the fall of 2014 and continued to soften throughout 2015.

The softening of prices beginning in late 2014 and continuing into 2015 caused average oil prices for both 2015 and 2014 periods to be below the average levels achieved in 2013. The NYMEX natural gas price per million British Thermal Units (MMBTU) averaged $2.61 in 2015, $4.33 in 2014 and $3.73 in 2013. NYMEX natural gas prices in 2015 were 40% below the average price in 2014, with the price decrease generally caused by domestic production elevating inventories to record levels and a much warmer than normal fourth quarter reducing residential demand. NYMEX natural gas prices in 2014 were 16% above the average price experienced in 2013, with the price increase generally caused by colder average winter season temperatures in North America in the later year. On an energy equivalent basis, the market continued to discount North American natural gas and NGL compared to crude oil in 2015. Crude oil prices in early 2016 have been significantly below the 2015 average prices, and natural gas prices in North America in 2016 have thus far been below the 2015 levels due to excess supply partially due to warmer than normal temperatures across much of the Northern U.S. during the early winter season of 2015-2016.

On June 23, 2016, the Company s Canadian subsidiary, Murphy Oil Company Ltd., closed the sale of its 5% non-operated working interest in Syncrude Canada Ltd. to Suncor Energy Inc. The transaction was previously announced on April 27, 2016, with an effective date of April 1, 2016. This non-core asset divestiture positively impacted corporate liquidity by increasing net cash on the balance sheet by $739.1 million before-tax.

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Results of Operations

Murphy Oil s results of operations, with associated diluted earnings per share (EPS), for the six months ended June 30, 2016 and 2015 and the last three years ended December 31 are presented in the following table.

	Six Months Ended June 30,		Years Ended December 31,		
(Millions of dollars, except EPS)	**2016**	**2015**	**2015**	**2014**	**2013**
Net income (loss)	$ (195.9)	$ (88.3)	$ (2,270.8)	905.6	1,123.5
Diluted EPS	(1.14)	(0.50)	(13.03)	5.03	5.94
Income (loss) from continuing operations	$ (196.6)	$ (85.5)	$ (2,255.8)	1,025.0	888.1
Diluted EPS	(1.14)	(0.48)	(12.94)	5.69	4.69
Income (loss) from discontinued operations	$ 0.7	$ (2.8)	$ (15.0)	(119.4)	235.4
Diluted EPS		(0.02)	(0.09)	(0.66)	1.25

Murphy Oil s net loss in 2015 was primarily caused by impairment expense to reduce the carrying value of certain properties in the Gulf of Mexico, Western Canada and Malaysia, lower realized sales prices for oil and natural gas, lower oil and natural gas sales volumes, and the costs of exiting deepwater rig contracts in the Gulf of Mexico. Results of continuing operations in 2015 were $3,280.8 million worse than 2014 and included a $218.8 million after- tax gain on sale of 10% of the Company s oil and gas assets in Malaysia. Results in 2014 included a $321.4 million after-tax gain on sale of 20% of the Company s oil and gas assets in Malaysia. Excluding this gain in Malaysia from both years, results from continuing operations in 2015 were $3,178.2 million below the prior year, primarily due to the reasons mentioned above. In 2015 and 2014, the Company s U.K. refining and marketing operations generated losses of $14.8 million and $120.6 million, respectively, which led to overall losses from discontinued operations in each year.

The Company s net income in 2014 was 19% lower than 2013, primarily due to an unfavorable variance in the results of discontinued operations between years. In August 2013, the Company distributed to its shareholders through a spin-off transaction all of the U.S. retail marketing operations. This business generated after-tax income of $134.8 million in 2013. Additionally, in early 2013, the Company sold all of its U.K. oil and gas assets, which including a gain on the disposal, generated income of $219.8 million in 2013. In 2014 and 2013, the Company s U.K. refining and marketing operations generated losses of $120.6 million and $119.2 million, respectively. Income from continuing operations in 2014 exceeded 2013 results by 15% and included a $321.4 million after-tax gain on sale of 20% of the Company s oil and gas assets in Malaysia. Excluding this gain in Malaysia, profits from continuing operations in 2014 were $184.5 million below the prior year, primarily due to lower average realized oil sales prices during 2014 compared to 2013.

Six months ended June 30, 2016 versus six months ended June 30, 2015

For the first six months of 2016, net loss totaled $195.9 million ($1.14 per diluted share) compared to a net loss of $88.3 million ($0.50 per diluted share) for the same period in 2015. Continuing operations had a loss of $196.6 million ($1.14 per diluted share) in the first six months of 2016, compared to a loss of $85.5 million ($0.48 per diluted share) in the same period of 2015. In the first half of 2016, the Company s exploration and production operations incurred a loss of $124.4 million compared to a loss of $32.5 million in the same period of 2015. Exploration and production loss in 2016 was higher than the 2015 period primarily due to lower revenues resulting from significantly lower realized oil and natural gas sales prices and lower volume sold, impairment expenses in Canada in 2016 and lower after-tax gains on assets sold. These were partially offset by lower lease operating expenses and production taxes, lower depreciation expense, lower exploration costs and lower expenses for environmental costs. Corporate after-tax costs were $72.2 million in the 2016 period compared to after-tax costs of $53.0 million in the 2015 period as the current period had lower gains for the effects of foreign currency exchange and higher net interest costs, partially offset by lower administrative costs. Net loss in the first half of 2016 included income from discontinued operations of $0.7 million ($0.00 per diluted share) compared to a loss of $2.8 million ($0.02 per diluted share) in the 2015 period. Discontinued operations in both periods primarily consists of costs related to winding down of all operations in the U.K. The final components of the refining and marketing operations were sold at the end of the second quarter 2015.

2015 versus 2014

Net loss in 2015 totaled $2,270.8 million ($13.03 per diluted share) compared to 2014 net income of $905.6 million ($5.03 per diluted share). Continuing operations results in 2015 were significantly weaker, recording a loss of $2,255.8 million ($12.94 per diluted share), while 2014 had income of $1,025.0 million ($5.69 per diluted share). The 2015 unfavorable variance for results of continuing operations was primarily associated with impairment expense, lower realized sales prices for oil and natural gas, lower oil and natural gas sales volumes, costs of existing deepwater rig contracts in the Gulf of Mexico, a deferred tax charge associated with a distribution from a foreign subsidiary, and lower after-tax gains generated from sale of oil and gas assets in Malaysia, partially offset by higher unrealized gains on crude oil contracts.

Lower oil and gas production volumes and lower costs for services led to lower overall extraction costs in 2015. The 2015 results were also favorably affected by higher foreign exchange gains and lower overall administrative costs. The results of discontinued operations were a loss of $15.0 million ($0.09 per diluted share) in 2015 compared to a loss of $119.4 million ($0.66 per diluted share) in 2014. The prior year s results for discontinued operations included an impairment charge associated with its Milford Haven, Wales refinery, partially offset by a gain on disposition of the U.K. retail marketing fuel stations in the prior year.

Sales and other operating revenues in 2015 were $2.5 billion below 2014 due to both weaker oil and natural sales prices and lower oil and natural gas sales volumes in 2015 compared to 2014. Average crude oil sales prices and North American natural gas sales prices realized in 2015 fell by 45% and 37%, respectively, compared to the prior year and sales volumes fell by approximately 7% in 2015 on a barrel of oil equivalent basis. Realized oil prices were significantly lower in 2015 due to an oversupply of crude oil available on a worldwide scale. The decrease in sales volumes was mostly attributable to the late 2014 and early 2015 sale of a combined 30% interest in its Malaysia assets nearly offset by growth in the Eagle Ford Shale in South Texas and higher production from the Tupper area in Western Canada.

Gain on sale of assets was $15.3 million higher in 2015, primarily associated with a pretax gain of $155.1 million generated on sale of 10% of the Company s oil and gas assets in Malaysia compared to $144.8 million gain on sale of 20% in 2014. Interest and other income in 2015 was $43.6 million above 2014 levels primarily due to higher profits realized on changes in foreign exchange rates during 2015. Lease operating expenses declined $257.6 million in 2015 compared to 2014 essentially due to sale of interests in Malaysia, lower service costs, cost saving initiatives and a lower average foreign exchange rate in Canada. Severance and ad valorem taxes decreased by $41.4 million in 2015 primarily due to lower average realized sales prices for oil and natural gas volumes in the United States.

Exploration expenses were $42.7 million less than 2014 primarily due to lower geological and geophysical costs and lower exploration costs in other foreign areas. Selling and general expenses in 2015 decreased by nearly 16% from 2014 as the Company implemented key organizational changes including lowering staffing levels by over 20% from end of the prior year. Depreciation, depletion and amortization expenses fell by $286.4 million due to both lower volume sold and lower per-unit capital amortization rates. Impairment expense associated with asset writedowns increased by $2.4 billion primarily due to the significant decline in current and future oil prices during 2015 resulting in writedowns of assets in the Seal heavy oil field in Western Canada and oil and natural gas fields offshore Malaysia and deepwater Gulf of Mexico. The deepwater rig contract exit costs of $282.0 million are for two deepwater rigs that were under contract in the Gulf of Mexico. These rigs were stacked before their contract expiration dates and the remaining obligations owed in 2016 under the contracts were expensed in 2015.

Interest expense in 2015 was $11.8 million lower than 2014 due principally to lower average borrowing levels in the 2015 period. Interest costs capitalized decreased by $13.3 million in 2015 due to fewer ongoing development projects in the 2015 period. Other operating expense was $53.7 million higher in 2015 compared to 2014 primarily due to recording estimated costs of remediating a site at the Seal field in a remote area of Alberta. Income tax benefits in 2015 were $1.0 billion compared to expense of $227.3 million in the prior year. The benefits reported in 2015 were the result of large pre-tax losses, a significant portion of which is related to impairments in the 2015 period, no local income taxes owed on the Malaysia sale, and deferred tax benefit on the sale due to the purchaser assuming certain future tax payment obligations, offset in part by a deferred tax charge in the U.S. associated with a $2.0 billion distribution from a foreign subsidiary to its parent in December 2015.

The effective tax rate in 2015 was 31.3% up from 18.2% in 2014. The 2014 period benefited from Malaysia tax benefits upon sale of 20% interest and higher U.S. tax benefits on foreign exploration areas.

2014 versus 2013

Net income in 2014 totaled $905.6 million ($5.03 per diluted share) compared to 2013 net income of $1,123.5 million ($5.94 per diluted share). Income from continuing operations increased in 2014, amounting to $1,025.0 million ($5.69 per diluted share), while 2013 amounted to $888.1 million ($4.69 per diluted share). The 2014 increase for continuing operations was primarily associated with a $321.4 million after-tax gain generated from sale of 20% of our oil and gas assets in Malaysia. Additionally, the Company s earnings in 2014 benefited from sale of 10% more oil and 5% more natural gas compared to 2013, but the average realized sales price for crude oil was 8% lower in 2014 compared to 2013. Higher oil and gas production volumes led to higher overall extraction costs in 2014, plus the significant weakening of oil and gas prices in late 2014 led to higher impairment expense compared to 2013. Net interest expense was higher in 2014 compared to 2013 due to a combination of more borrowings and lower amounts capitalized to oil and gas development projects.

The 2014 results were favorably affected by slightly higher tax benefits associated with foreign exploration activities and lower overall administrative costs. The results of discontinued operations were a loss of $119.4 million ($0.66 per diluted share) in 2014 compared to earnings of $235.4 million ($1.25 per diluted share) in 2013. The results for discontinued operations in 2013 included a $216.1 million after-tax gain on sale of U.K. oil and gas properties as well as profitable operating results of $134.8 million from U.S. retail marketing operations that were spun-off to shareholders in August 2013. The losses generated by U.K. refining and marketing operations were similar in both years.

Sales and other operating revenues in 2014 were $23.8 million below 2013 as higher oil and natural gas sales volumes in the later year were more than offset by weaker oil sales prices compared to 2013. Sales volumes grew by 8.5% in 2014 on a barrel of oil equivalent basis, but average crude oil sales prices realized in 2014 fell by 8% compared to 2013. The overall increase in sales volumes was mostly attributable to growth in the Eagle Ford Shale in South Texas. Oil prices declined sharply in late 2014 due to an oversupply of crude oil available on a worldwide scale. Gain on sale of assets was $139.0 million higher in 2014, primarily associated with a pretax gain of $144.8 million generated on sale of 20% of the Company s oil and gas assets in Malaysia in December 2014. Interest and other income in 2014 was $29.2 million below 2013 levels primarily due to lower profits realized on changes in foreign exchange rates during the later year.

Lease operating expenses declined $162.9 million in 2014 compared to 2013 essentially due to nonrecurring costs in the earlier year upon shut down of oil production operations in Republic of the Congo. Severance and ad valorem taxes increased by $19.9 million in 2014 caused by higher volume of oil produced and a higher well count in the Eagle Ford Shale. Exploration expenses increased $11.4 million in 2014 compared to 2013 primarily

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due to higher amortization costs associated with Eagle Ford Shale leaseholds. Higher costs in 2014 for exploratory drilling were mostly offset by lower seismic costs compared to 2013. Selling and general expense was reduced by $15.2 million in 2014 compared to the prior year mostly related to nonrecurring costs in 2013 associated with the spin-off of the U.S. retail marketing business to shareholders.

Depreciation, depletion and amortization expense rose $352.9 million in 2014 due to both higher overall oil and natural gas production levels and higher per-unit capital amortization rates in areas where production growth was achieved. Impairment expense associated with asset writedowns increased $29.7 million in 2014 primarily due to non-recoverability of goodwill for conventional operations in Canada that was originally recorded in association with an oil and gas company acquisition in 2000. Accretion expense increased $1.8 million in 2014 primarily due to added levels of discounted asset retirement liabilities associated with development drilling in the Gulf of Mexico. Interest expense in 2014 was $12.0 million more than the prior year due to higher average borrowing levels compared to 2013. Interest costs capitalized in 2014 were $31.9 million below 2013 levels due to fewer ongoing oil development projects during the later year.

Other operating expense was $24.9 million in 2014 and primarily included costs associated with write-down of materials inventory in Malaysia. Income tax expense was $357.3 million lower in 2014 compared to 2013 due to a combination of deferred tax benefits associated with the sale of Malaysia assets and sanction of a development in Block H Malaysia, larger U.S. tax benefits related to exploration losses in foreign areas where the Company has completed operations and exited the area, and lower overall pretax earnings. As to the Malaysia sale, no local income taxes were owed and a deferred tax benefit arose due to the purchaser assuming certain future tax payment obligations. The effective tax rate in 2014 was 18.2%, down from 39.7% in 2013. The Malaysian tax benefits upon sale of 20% interest, combined with higher U.S. tax benefits on foreign exploration areas led to an effective tax rate for the Company in 2014 below the 35.0% U.S. statutory tax rate.

Segment Results In the following table, the Company s results of operations for the six months ended June 30, 2016 and 2015 and the last three years ended December 31 are presented by segment. More detailed reviews of operating results for the Company s exploration and production and other activities follow the table.

	Six Months Ended June 30,				
(Millions of dollars)	**2016**	**2015**	**2015**	**2014**	**2013**
Exploration and production - continuing operations					
United States	$ (131.4)	$ (110.4)	$ (615.7)	$ 387.1	$ 435.4
Canada	(31.9)	(70.7)	(583.4)	156.5	180.8
Malaysia	70.1	250.7	(653.2)	896.2	786.4
Other	(31.2)	(102.1)	(158.6)	(250.0)	(373.8)
Total exploration and production - continuing operations	(124.4)	(32.5)	(2,010.9)	1,189.8	1,028.8
Corporate and other	(72.2)	(53.0)	(244.9)	(164.8)	(140.7)
Income (loss) from continuing operations	(196.6)	(85.5)	(2,255.8)	1,025.0	888.1
Income (loss) from discontinued operations	0.7	(2.8)	(15.0)	(119.4)	235.4

Net income (loss)	$ (195.9)	$ (88.3)	$ (2,270.8)	$ 905.6	$ 1,123.5

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Exploration and Production

Six months ended June 30, 2016 versus six months ended June 30, 2015

United States exploration and production operations reported a loss of $131.4 million in the first half of 2016 compared to a loss of $110.4 million in the 2015 period. The loss increased $21.0 million in 2016 compared to the 2015 period due to lower revenues partially offset by lower production costs and lower exploration expenses. Revenue in the U.S. fell $301.6 million in the period due to both lower oil and natural gas realized sales prices and lower volumes sold. Lease operating expenses decreased by $70.4 million due to lower costs in Eagle Ford Shale and offshore Gulf of Mexico compared to the same period in 2015 with most of the reduction due to the Company aggressively attacking its cost structure coupled with lower variable costs based on volumes produced. Severance and ad valorem taxes in the first half of 2016 were $13.0 million lower than the 2015 period primarily due to weaker average commodity prices and lower volume sold. Depreciation expense decreased $86.2 million in 2016 compared to 2015 due to lower unit rates in Eagle Ford Shale in the 2016 period and lower U.S. volume sold. Exploration expenses were down $86.1 million in the 2016 period primarily related to lower dry hole costs of $64.9 million and lower undeveloped lease amortization compared to the first half of 2015.

Operations in Canada had a loss of $31.9 million in the first half of 2016 compared to a loss of $70.7 million in the 2015 six months. Canadian results of operations improved by $38.8 million in the 2016 period. Results for conventional operations worsened by $27.7 million in 2016 due to impairment expense, lower average realized sales prices for crude oil and natural gas and lower oil volume sold. These were partially offset by higher natural gas volumes produced, lower production costs, no repeat of prior year charges for an environmental provision at the Seal heavy oil area, income tax benefits recognized on the sale of certain Montney midstream assets in 2016, and no repeat of a tax adjustment in 2015 for a 2% increase in the statutory tax rate in Alberta. Lease operating expenses associated with conventional operations were $15.6 million lower in the first six months of 2016 due to both lower costs and a weaker Canadian dollar exchange rate. Depreciation expense was $28.7 million lower in the 2016 period compared to 2015 due primarily to lower unit rates and mix of volume sold. Impairment expense was $95.1 million in 2016, as low oil prices led to a write down of heavy oil properties at Seal in Western Canada and the Terra Nova field offshore East Coast Canada in the first quarter of the year. Synthetic operations generated $47.9 million in income in 2016 compared to a loss of $18.6 million in the same period of 2015. A $71.7 million after-tax gain on sale of the Company s non-operated interest in Syncrude completed at the end of the second quarter was the primary driver of the improvement. Normal operating results were $5.2 million lower in the 2016 period versus the 2015 quarter. Lower oil sales prices and lower volume sold in the 2016 period were partially offset by lower supply costs and no reoccurrence of the 2015 adjustment related to the aforementioned increase in the Alberta statutory tax rate. Lease operating expenses associated with synthetic operations were $17.6 million lower in the 2016 quarter due to lower variable costs and a weaker Canadian dollar exchange rate. Depreciation expense declined $8.9 million in the 2016 period due to lower unit rate and lower volume produced. Production volumes, lease operating expense and depreciation expense were significantly impacted by the facility being shut-in for 44 days of the quarter due to forest fires in the area.

Malaysia operations reported earnings of $70.1 million in the first half of 2016 compared to earnings of $250.7 million during the same period in 2015. Results were down $180.6 million in 2016 in Malaysia primarily due to a $218.8 million after-tax gain on sale of a 10% interest in Malaysian assets in the 2015 period. Revenue declined by $351.4 million driven by lower commodity prices received and lower volumes sold in the 2016 period, but this was partially offset by lower lease operating expenses and lower depreciation expense. Lease operating expenses decreased in the 2016 period by $40.7 million due to lower maintenance costs and cost cutting measures, and lower volume sold compared to 2015. Depreciation expense was $222.6 million lower in 2016 compared to the same period in 2015 primarily due to lower unit rates following 2015 impairment charges at certain producing properties and lower oil and natural gas volumes sold.

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Other international operations reported a loss of $31.2 million in the first six months of 2016 compared to a loss of $102.1 million in the 2015 period. The 2016 period included lower dry hole costs of $23.9 million, with the higher 2015 costs primarily associated with unsuccessful wildcat drilling offshore Australia. Geological and geophysical costs were $12.6 million lower in the 2016 period, primarily due to less seismic data acquired in Australia. Other exploration expenses were $6.7 million lower in the current year, mostly attributable to the Company closing certain field offices beginning in late 2015 and aggressively attacking its cost structure. Other expenses were $21.0 million less in the 2016 period primarily related to an adjustment of previously recorded exit costs in the current period associated with ceasing production operations in Republic of Congo versus a charge in the 2015 period for uncollectible receivables from partners in Murphy West Africa.

2015 versus 2014

Exploration and production (E&P) continuing operations recorded a loss of $2,010.9 million in 2015 compared to earnings of $1,189.8 million in 2014 and $1,028.8 million in 2013. Results from exploration and production operations decreased $3,200.7 million in 2015 compared to 2014 primarily due to impairment expense, lower realized sales prices for oil and natural gas, lower oil and natural gas sales volumes, deepwater rig contract exit costs and lower after-tax gains on sale of interests in Malaysia, offset in part by lower extraction costs and lower selling and general expenses. Crude oil sales prices fell during 2015 in all areas of the Company s operations, and crude oil price realizations averaged $47.99 per barrel in 2015 compared to $87.23 per barrel in 2014, a price drop of 45% year on year. North America natural gas sales prices and Malaysia natural gas sold at Sarawak fell 37% and 26%, respectively, compared to 2014. Oil and gas extraction costs, including associated production taxes, on a per-unit basis, improved by 13% in 2015 and, together with lower oil and natural gas volumes sold, resulted in $588.6 million in lower costs.

Compared to 2014, total sales volumes in 2015 for crude oil and natural gas fell 9% and 4%, respectively, while natural gas liquids sales volumes rose 8%. Oil sale volumes were lower primarily due to the sale of 30% of its interests in Malaysia over December 2014 and January 2015, partially offset by production growth in the Eagle Ford Shale and new fields brought on-stream in Malaysia in 2014. Natural gas liquid sales volumes increased due to growth in Eagle Ford Shale. Natural gas sales volumes fell primarily due to the decline in Malaysia resulting from the sale of 30% of the Company s interest and were nearly offset by 26% increase in Canada due to new wells in 2015 and in the second half of 2014 and improved recovery techniques. Heavy oil sales volumes in the Seal area of Canada were lower in 2015 due to well decline and uneconomic wells being shut-in. Also, more downtime for synthetic oil operations led to slightly lower sales volumes in 2015.

Lease operating expenses declined $257.6 million in 2015 compared to 2014 essentially due to sale of interests in Malaysia, lower service costs, cost saving initiatives and a lower average foreign exchange rate in Canada. Severance and ad valorem taxes decreased by $41.4 million in 2015 primarily due to lower average realized sales prices for oil and natural gas volumes in the United States. Exploration expenses were $42.7 million less than 2014 primarily due to lower geological and geophysical costs and lower exploration costs in other foreign areas. Selling and general expenses decreased by 16% over 2014 as the Company implemented key organizational changes including lowering staffing levels by 20% from the end of 2014.

Depreciation, depletion and amortization expense fell by $289.6 million due to both lower volume sold and lower per-unit capital amortization rates. Impairment expense associated with asset writedowns was approximately $2.5 billion in 2015 compared to $51 million in 2014. The increase is primarily due to the significant decline in current and future oil prices during 2015 resulting in writedowns of assets in the Seal heavy oil field in Western Canada, and oil and natural gas fields offshore Malaysia and deepwater Gulf of Mexico. The deepwater rig contract exit costs of $282.0 million are for two deepwater rigs that were under contract in the Gulf of Mexico and were stacked before their contract expiration dates. The remaining obligations owed in 2016 under the rig contracts were expensed in

2015.

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Other operating expense was $53.7 million higher in 2015 compared to 2014 primarily due to recording estimated costs of remediating a site at the Seal field in a remote area of Alberta. Income tax benefits in 2015 were $1.1 billion compared to expense of $285.7 million in 2014. The benefits reported in 2015 were result of large pre-tax losses, a significant portion of which is related to impairments in the 2015 period, plus no local income taxes owed on the Malaysia sale and a deferred tax benefit due to the purchaser assuming certain future tax payment obligations. The effective tax rate in 2015 was 35.6% up from 19.4% in 2014. The 2014 period benefited from Malaysia tax benefits upon sale of 20% interest and higher U.S. tax benefits on foreign exploration areas.

2014 versus 2013

E&P income from continuing operations increased $161.0 million in 2014 compared to 2013 primarily due to an after-tax gain of $321.4 million on sale of 20% of the Company s interest in Malaysia in late 2014. Excluding this gain in Malaysia, E&P earnings declined $160.4 million in 2014, essentially due to lower margins realized on oil sales. The margin decline was attributable to lower average crude oil sales prices in 2014. Crude oil sales prices fell during 2014 in all areas of the Company s operations, and crude oil price realizations averaged $87.23 per barrel compared to $94.96 per barrel in 2013, a price drop of 8% year on year.

Oil and gas extraction costs, including associated production taxes, were slightly lower on a per-unit basis, but increased overall by $210.8 million due to higher combined total oil and gas sales volumes of 8.5% during 2014. Compared to 2013, total sales volumes in 2014 for crude oil rose 6%, while natural gas liquids sales volumes rose 213% and natural gas sales volumes rose 5%. These 2014 increases in crude oil and gas liquids sales volumes were primarily associated with growth in operations in the Eagle Ford Shale, while natural gas volumes increased due to both Eagle Ford Shale drilling and start-up of the Dalmatian field in the Gulf of Mexico. Crude oil sales volumes offshore Sarawak Malaysia increased in 2014 due to a full year of production from new oil fields brought online in 2013. Crude oil sales volumes in 2014 offshore Block K Malaysia were less than 2013 due to lower production at the Kikeh field coupled with an underlift of sales volumes based on timing of the Company s cargo sales. Heavy oil sales volumes in Canada were lower in 2014 due to well decline in the Seal area. Also, more downtime for synthetic oil operations led to lower sales volumes in 2014. The final cargo sale in Republic of the Congo occurred in early 2013 and the field has been abandoned.

The Company brought on new natural gas wells in the Tupper area of Western Canada in the second half of 2014, but these new gas volumes did not fully offset production decline at other gas wells in the area during the full year 2014. Lease operating expenses were $163.0 million lower in 2014 primarily due to no repeat of 2013 costs associated with the now abandoned Azurite field in Republic of the Congo. Excluding the costs in Republic of the Congo, lease operating expenses increased by $28.0 million in 2014, primarily due to higher oil and gas production levels in the Eagle Ford Shale area. Severance and ad valorem taxes increased $19.9 million in 2014 compared to the prior year due to continued growth in production volumes and well count in the Eagle Ford Shale. Depreciation expense for E&P operations increased $353.9 million in 2014 due to higher overall production levels and capital amortization rates above the Company s average for new production added in the Gulf of Mexico and offshore Malaysia.

Accretion expense related to discounted asset retirement obligations increased $1.8 million as expense associated with new wells in the Gulf of Mexico and offshore Malaysia was only partially offset by the favorable effect of settling abandonment obligations in Republic of the Congo. Asset impairment expense of $51.3 million in 2014 was higher by $29.7 million; significantly weaker oil and gas prices at year-end 2014 led to writedown of a natural gas field in the Gulf of Mexico and writeoff of goodwill associated with an oil and gas company acquired in 2000 in Western Canada. Exploration expense was $11.4 million higher in 2014 due to larger amortization costs associated with dropping remote undeveloped leases in the Eagle Ford Shale. Additionally, the Company had increased costs in 2014 for exploratory wells drilled in an earlier year in the Gulf of Mexico

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and Malaysia that were expensed due to significantly lower natural gas prices and denial of a requested gas holding period extension, respectively. This was partially offset by lower seismic costs incurred in 2014 in Southeast Asia.

Selling and general expenses for E&P operations increased $41.1 million in 2014 compared to the prior year due to higher overall staffing levels and less costs recovered from partners in Malaysia due to fewer development activities ongoing during 2014. Other expenses were $24.9 million in 2014 and primarily related to writedown in value of materials inventory associated with Malaysia operations. Income tax expense for E&P operations in 2014 was $370.6 million below 2013 levels due to lower pretax earnings, a benefit related to future tax liabilities assumed by the purchaser of 20% of assets in Malaysia, a benefit associated with sanction of a development plan in Block H Malaysia, and higher U.S. tax benefits in 2014 associated with foreign operations that were exited.

The results of operations for oil and gas producing activities for each of the six months ended June 30, 2016 and 2015 and each of the last three years are shown by major operating areas on pages F-59 and F-60 of the financial statements included elsewhere and incorporated by reference in this prospectus supplement and the accompanying prospectus.

A summary of oil and gas revenues is presented in the following table.

	Six Months Ended June 30,				
(Millions of dollars)	**2016**	**2015**	**2015**	**2014**	**2013**
United States Oil and gas liquids	$ 381.5	$ 570.9	$ 1,176.9	$ 2,062.1	$ 1,724.7
Natural gas	14.7	41.4	70.4	127.2	72.7
Canada Conventional oil and gas liquids	65.2	114.2	181.0	453.3	507.2
Synthetic oil	60.7	105.7	203.0	391.5	441.0
Natural gas	54.3	85.3	167.7	201.3	198.1
Malaysia Oil and gas liquids	275.4	445.1	790.6	1,680.2	1,875.0
Natural gas	64.9	89.6	185.4	357.5	404.0
Republic of the Congo oil					83.6
Total oil and gas revenues	$ 916.7	$ 1,452.2	$ 2,775.0	$ 5,273.1	$ 5,306.3

The following table contains selected operating statistics for the six months ended June 30, 2016 and 2015 and the last three years ended December 31.

	Six Months Ended June 30,				
	2016	**2015**	**2015**	**2014**	**2013**
Net crude oil and condensate produced barrels per day					
United States Eagle Ford Shale	38,550	48,483	47,325	45,534	33,580
Gulf of Mexico	13,331	12,519	13,794	14,366	11,943
Canada light	540	110	115	47	59
heavy	2,759	6,276	5,341	7,411	9,123
offshore	8,020	7,702	7,421	8,758	9,099
synthetic	9,326	11,394	11,699	11,997	12,886
Malaysia Sarawak(1)	13,490	15,951	15,249	20,274	10,323

Block K	25,219	28,343	25,456	34,021	42,808
Republic of the Congo					1,046
Continuing operations	111,235	130,778	126,400	142,408	130,867
Discontinued operations United Kingdom					648
Total crude oil and condensate produced	111,235	130,778	126,400	142,408	131,515

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	Six Months Ended June 30,				
	2016	**2015**	**2015**	**2014**	**2013**
Net crude oil and condensate sold barrels per day					
United States Eagle Ford Shale	38,550	48,483	47,326	45,534	33,580
Gulf of Mexico	13,331	12,519	13,794	14,366	11,943
Canada light	540	110	115	47	59
heavy	2,759	6,276	5,341	7,411	9,123
offshore	8,348	8,065	7,151	8,789	8,586
synthetic	9,326	11,394	11,699	11,997	12,886
Malaysia(1) Sarawak	11,712	17,066	16,360	19,991	10,728
Block K	23,488	27,793	26,583	32,578	43,482
Republic of the Congo					2,093
Continuing operations	108,054	131,706	128,369	140,713	132,480
Discontinued operations United Kingdom					621
Total crude oil and condensate sold	108,054	131,706	128,369	140,713	133,101
Net natural gas liquids produced barrels per day					
United States Eagle Ford Shale	6,988	7,517	7,558	5,778	2,064
Gulf of Mexico	1,347	1,895	1,998	2,596	800
Canada	88	14	10	25	64
Malaysia(1) Sarawak	635	668	668	840	635
Total net gas liquids produced	9,058	10,094	10,234	9,239	3,563
Net natural gas liquids sold barrels per day					
United States Eagle Ford Shale	6,988	7,517	7,558	5,778	2,064
Gulf of Mexico	1,347	1,895	1,998	2,596	800
Canada	88	14	10	25	64
Malaysia(1) Sarawak	1,127	368	606	986	66
Total net natural gas liquids sold	9,550	9,794	10,172	9,385	2,994
Net natural gas sold thousands of cubic feet per day					
United States Eagle Ford Shale	37,203	39,030	38,304	33,370	20,571
Gulf of Mexico	20,094	55,563	49,068	55,101	32,641
Canada	207,288	193,133	196,774	156,478	175,449
Malaysia(1) Sarawak	97,155	111,431	121,650	168,712	164,671
Block K	12,124	25,804	21,818	32,295	29,699
Continuing operations	373,864	424,961	427,614	445,956	423,031
Discontinued operations United Kingdom					815
Total natural gas sold	373,864	424,961	427,614	445,956	423,846
Total net hydrocarbons produced equivalent barrels per day(2)	182,604	211,699	207,903	225,973	205,719
Total net hydrocarbons sold equivalent barrels per day(2)	179,915	212,327	209,809	224,454	206,736
Estimated net hydrocarbon reserves million equivalent barrels(2),(3)			774.0	756.5	687.9

(1) The Company sold 20% interest in Malaysia properties on December 18, 2014 and sold an additional 10% interest on January 29, 2015. This table includes volumes for these sold interests through the date of disposition.

(2) Natural gas converted at a 6:1 ratio.

(3) At December 31.

Six months ended June 30, 2016 versus six months ended June 30, 2015

Total worldwide production averaged 182,604 barrels of oil equivalent per day during the six months ended June 30, 2016, a decrease from 211,699 barrels of oil equivalent produced in the same period in 2015. Crude oil and condensate production in the first half of 2016 averaged 111,235 barrels per day compared to 130,778 barrels per day in the first half of 2015. Crude oil production decreased 9,933 barrels per day in the Eagle Ford Shale in 2016 due to well decline associated with significantly less drilling beginning in the last half of 2015 and continuing into 2016 in response to lower prices. Heavy oil production in Canada declined in 2016 in the Seal area of Western Canada primarily due to uneconomic well volumes shut-in caused by low sales prices, and natural decline. Synthetic oil production in Canada also was lower in 2016 due to impacts of maintenance work and downtime associated with forest fires in the surrounding area. Lower oil production in 2016 in Malaysia was primarily attributable to natural well decline. Total production of natural gas liquids was 9,058 barrels per day in the 2016 period compared to 10,094 barrels per day a year ago. Natural gas sales volumes decreased from 425 million cubic feet per day in 2015 to 374 million cubic feet per day in 2016. Natural gas sales volumes increased in North America due to higher gas production volumes in the Tupper area in Western Canada and Eagle Ford Shale area of South Texas, offset in part by lower gas volumes in the Gulf of Mexico primarily in the Dalmatian field. The increase in North America was more than offset by lower production in Malaysia due to unplanned downtime in both Sarawak and Block K.

2015 versus 2014

The Company s total crude oil and condensate production averaged 126,400 barrels per day in 2015, compared to 142,408 barrels per day in 2014. The 2015 crude oil production level was 11% below 2014. On a pro-forma basis, assuming the sale of 30% of the Company s interest in Malaysia properties occurred at the beginning of 2014, total hydrocarbon production for 2015 increased 4% compared to the 2014 period as adjusted for the sale. Crude oil production in the United States totaled 61,119 barrels per day in 2015, up from 59,900 barrels per day in 2014. The 2% increase in U.S. crude oil production year over year was primarily related to additional wells brought on production as part of an ongoing development drilling and completion program at Eagle Ford Shale in South Texas. Heavy crude oil production in Western Canada fell from 7,411 barrels per day in 2014 to 5,341 barrels per day in 2015, with the reduction attributable to wells shut-in due to economic conditions and natural well performance decline in the Seal area. Crude oil volumes produced offshore Eastern Canada totaled 7,421 barrels per day in 2015, off from 8,758 barrels per day in the previous year due to less production at Hibernia field primarily due to planned maintenance in 2015. Synthetic crude oil production volume in Canada was 11,699 barrels per day in 2015 compared to 11,997 barrels per day in 2014 due to impacts of unplanned outages offset in part by lower Canadian royalty rates. Crude oil production offshore Sarawak decreased from 20,274 barrels per day in 2014 to 15,249 barrels per day in 2015. Block K in Malaysia had crude oil production of 25,456 barrels per day in 2015, down from 34,021 barrels per day in 2014. Lower oil production in 2015 in Malaysia was primarily attributable to impacts from the sale of 30% of the Company s total interest offset in part by production from new fields brought on-stream in 2014.

The Company produced natural gas liquids (NGL) of 10,234 barrels per day in 2015, up from 9,239 barrels per day in 2014. The higher NGL volumes of 995 barrels per day in 2015 were mostly attributable to the increase of 1,780 barrels per day in the Eagle Ford Shale partially offset by well decline in Gulf of Mexico and the sale of 30% of its interests in Malaysia.

Worldwide sales of natural gas were 427.6 million cubic feet (MMCF) per day in 2015, compared to 446.0 MMCF per day in 2014. Natural gas sales volumes decreased in 2015, primarily due to the decline in Malaysia after the sale of 30% of the Company s interests, offset in part by higher gas production volumes in the Dalmatian field in the Gulf of Mexico, Eagle Ford Shale area in South Texas and Tupper area in Western Canada. Natural gas sales volumes in Canada improved from 156.5 MMCF per day in 2014 to 196.8 MMCF per day in 2015 due to wells added during 2015 and in the second half of 2014 and improved recovery techniques. At the Company s fields offshore Sarawak Malaysia, gas production decreased from 168.7 MMCF per day in 2014 to 121.7 MMCF per day in 2015 due to sale of 30% interest in Malaysian properties. Natural gas sales volumes from Block K offshore Malaysia were 21.8 MMCF per day in 2015, down from 32.3 MMCF per day in 2014 due to the sale of 30% of the Company s interests and higher downtime at the third party receiving facility.

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2014 versus 2013

Crude oil production in 2014 totaled 142,408 barrels per day compared to 131,515 barrels per day in 2013. The 2014 crude oil production level was a Company record and 8% above 2013. Crude oil production in the United States totaled 59,900 barrels per day in 2014, up from 45,523 barrels per day in 2013. The 32% increase in U.S. crude oil production year over year was a U.S. record for the Company and was primarily related to increased volumes produced in the Eagle Ford Shale in South Texas. The Company s Eagle Ford Shale drilling program utilized an average of almost eight drilling rigs during 2014. U.S. production also benefited in 2014 from start-up of the Dalmatian field in the Gulf of Mexico. Heavy crude oil production in Western Canada fell from 9,123 barrels per day in 2013 to 7,411 barrels per day in 2014, with the reduction attributable to well performance decline in the Seal area.

Crude oil volumes produced offshore Eastern Canada totaled 8,758 barrels per day in 2014, off from 9,099 barrels per day in the previous year as well decline at Hibernia was not fully offset by the benefit of less 2014 downtime at Terra Nova. Synthetic crude oil production volume was 11,997 barrels per day in 2014 compared to 12,886 barrels per day in 2013 due to the latter year experiencing greater levels of downtime for repairs. Crude oil production offshore Sarawak increased from 10,323 barrels per day in 2013 to 20,274 barrels per day in 2014; the Company brought several new fields online during 2013 which provided a full year of production in 2014. Block K in Malaysia had crude oil production of 34,021 barrels per day in 2014, down from 42,808 barrels per day in 2013. Both the Kakap main field and the Siakap field came on stream during 2014, but this partial year production did not fully offset lower production at the Kikeh field. The Kikeh field had lower production in 2014 due to a combination of an outage for hook-up of the Siakap field, a facility fire early in the year, and normal well decline. Prior to going off production in early 2013, the Azurite field produced 1,046 barrels of crude oil per day. Additionally, discontinued fields in the U.K. that were all sold in early 2013 provided crude oil production of 648 barrels per day.

The Company produced NGL of 9,239 barrels per day in 2014, up from 3,563 barrels per day in 2013. The higher NGL volumes of 5,676 barrels per day in 2014 were mostly attributable to increases of 3,714 barrels per day in the Eagle Ford Shale and 1,227 barrels per day associated with start-up of the Dalmatian field in the Gulf of Mexico.

Worldwide sales of natural gas were 446.0 million cubic feet (MMCF) per day in 2014, compared to 423.8 MMCF per day in 2013. Significant development drilling in the Eagle Ford Shale and start-up of the Dalmatian field in the Gulf of Mexico drove up U.S. natural gas sales volumes from 53.2 MMCF per day in 2013 to 88.5 MMCF per day in 2014. Natural gas sales volumes in Canada fell from 175.4 MMCF per day in 2013 to 156.5 MMCF per day in 2014 as decline at existing wells in the Tupper area of British Columbia were not fully offset by gas volumes produced at new wells brought on line during 2014. At the Company s fields offshore Sarawak Malaysia, gas production increased from 164.7 MMCF per day in 2013 to 168.7 MMCF per day in 2014 due to higher customer demand in the later year. Natural gas sales volumes from Block K offshore Malaysia were 32.3 MMCF per day in 2014, up from 29.7 MMCF per day in 2013 due to higher demand from the third party receiving facility.

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The following table contains the weighted average sales prices for the six months ended June 30, 2016 and 2015 and the last three years ended December 31.

	Six Months Ended June 30,				
	2016	**2015**	**2015**	**2014**	**2013**
Weighted average sales prices					
Crude oil and condensate dollars per barrel					
United States Eagle Ford Shale	$ 38.93	$ 49.55	$ 48.14	$ 90.67	$ 101.02
Gulf of Mexico	39.00	52.52	46.80	91.18	103.63
Canada (1) light	33.74	46.16	41.06	83.43	85.61
heavy	11.83	27.02	23.28	54.18	46.78
offshore	36.82	55.51	50.54	95.95	108.64
synthetic	35.58	51.27	47.56	89.51	96.09
Malaysia Sarawak(2)	$ 41.74	$ 52.87	$ 50.13	$ 84.78	$ 101.93
Block K(2)	41.97	56.96	51.50	86.50	92.37
Republic of the Congo					109.43
Discontinued operations United Kingdom					108.67
Natural gas liquids dollars per barrel					
United States Eagle Ford Shale	9.65	12.22	11.18	25.79	28.71
Gulf of Mexico	10.59	14.50	12.82	28.93	34.30
Canada(1)	29.38	22.31	22.31	66.19	72.68
Malaysia Sarawak(2)	35.65	58.08	50.55	75.18	101.40
Natural gas dollars per thousand cubic feet					
United States Eagle Ford Shale	1.43	2.39	2.24	3.99	3.79
Gulf of Mexico	1.62	2.48	2.36	3.98	3.85
Canada(1)	1.44	2.44	2.35	3.60	3.09
Malaysia Sarawak(2)	3.52	4.53	4.23	5.71	6.66
Block K	0.25	0.24	0.24	0.24	0.24
Discontinued operations United Kingdom					12.32

(1) U.S. dollar equivalent.

(2) Prices are net of payments under the terms of the respective production sharing contracts.

Six months ended June 30, 2016 versus six months ended June 30, 2015

For the first six months of 2016, the Company s sales price for crude oil and condensate averaged $38.78 per barrel, down from $51.26 per barrel in 2015. The sales price for U.S. natural gas liquids averaged $9.80 per barrel in 2016 compared to $12.77 per barrel in 2015. The average sales price for North American natural gas in the first six months of 2016 was $1.45 per MCF, down from $2.44 per MCF realized in 2015. Natural gas production at fields offshore Sarawak was sold at an average realized price of $3.52 per MCF in 2016 compared to $4.53 per MCF in 2015.

2015 versus 2014

The Company s average worldwide realized sales price for crude oil and condensate from continuing operations was $47.99 per barrel in 2015 compared to $87.23 per barrel in 2014 and $94.96 per barrel in 2013. The average realized crude oil sales price was 45% lower in 2015 compared to the prior year. West Texas Intermediate (WTI) crude oil averaged 48% less in 2015. Dated Brent and Kikeh oil each sold for approximately 47% less in 2015, while Light Louisiana Sweet crude oil sold at 46% below 2014 levels. The average realized sales prices for U.S. crude oil and condensate amounted to $47.84 per barrel in 2015, 47% lower than 2014. Heavy oil produced in Canada brought $23.28 per barrel in 2015, a 57% decrease from 2014, as a result of lower worldwide benchmark prices in 2015. The average sales price for crude oil produced offshore Eastern Canada declined 47% to $50.54 per barrel in 2015. The average realized sales price for the Company s synthetic crude oil was $47.56 per barrel in 2015 down 47% from the prior year. Crude oil sold in Malaysia averaged $50.98 per barrel in 2015, 41% lower than in 2014.

The average sales price for natural gas liquids (NGL) was also lower in 2015 than 2014. These NGL prices are generally weak compared to the comparable heating value of crude oil, primarily due to an oversupply of NGL with the recent drilling growth in U.S. shale plays exceeding refinery and other demand for this product. NGL was sold in the U.S. for an average of $11.55 per barrel in 2015, down 57% from the average price of $26.83 per barrel in 2014. NGL produced in Malaysia in 2015 was sold for an average of $50.55 per barrel, 33% below the 2014 average of $75.18 per barrel.

North American natural gas prices were weaker in 2015 than 2014, essentially driven by record inventory levels and a warmer than normal fourth quarter in 2015. The average posted price at Henry Hub in Louisiana was $2.61 per million British Thermal Units (MMBTU) in 2015 compared to $4.33 per MMBTU in 2014. In 2015, U.S. natural gas was sold at an average of $2.31 per thousand cubic feet (MCF), a 42% decrease compared to 2014. Natural gas sold in Canada averaged $2.35 per MCF in 2015, down 35% from 2014. Natural gas sold in 2015 from Sarawak Malaysia averaged $4.23 per MCF, down 26% from the prior year.

Based on 2015 sales volumes and deducting taxes at statutory rates, each $1.00 per barrel oil sales price fluctuation and $0.10 per MCF gas sales price fluctuation would have affected 2015 earnings from exploration and production continuing operations by $30.6 million and $10.6 million, respectively.

2014 versus 2013

The Company s average worldwide realized sales price for crude oil and condensate from continuing operations was $87.23 per barrel in 2014 compared to $94.90 per barrel in 2013. The average realized crude oil sales price for continuing operations was 8% lower in 2014 compared to 2013. Although West Texas Intermediate (WTI) crude oil averaged 5% less in 2014, other indices on which the Company sells crude oil fell more compared to the prior year. Dated Brent and Kikeh oil each sold for 9% less in 2014, while Light Louisiana Sweet crude oil sold at 11% below 2013 levels. The average realized sales prices for U.S. crude oil and condensate amounted to $90.79 per barrel in 2014, 11% lower than 2013. Heavy oil produced in Canada brought $54.18 per barrel in 2014, a 16% increase from 2013, as a reduction in the discount for heavy oil in 2014 more than offset the impact of lower worldwide benchmark prices in 2014. The average sales price for crude oil produced offshore Eastern Canada declined 12% to $95.95 per barrel in 2014. The average realized sales price for the Company s synthetic crude oil was $89.51 per barrel in 2014 down 7% from the prior year. Crude oil sold in Malaysia averaged $85.85 per barrel in 2014, 9% lower than in 2013.

The average sales price for NGL was lower in 2014 than 2013. NGL was sold in the U.S. for an average of $26.83 per barrel in 2014, down 11% from the average price of $30.31 per barrel in 2013. NGL produced in Malaysia in 2014 was sold for an average of $75.18 per barrel, 26% below the 2013 average of $101.40 per barrel.

North American natural gas prices were stronger in 2014 than 2013, essentially driven by higher gas energy demand due to an extremely cold winter season on the continent. The average posted price at Henry Hub in Louisiana was $4.34 per MMBTU in 2014 compared to $3.72 per MMBTU in 2013. In 2014, U.S. natural gas was sold at an average of $3.98 per thousand cubic feet (MCF), a 4% increase compared to 2013. Natural gas sold in Canada averaged $3.60 per MCF in 2014, up 17% from 2013. Natural gas sold in 2014 from Sarawak Malaysia averaged $5.71 per MCF, down 14% from the prior year.

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Production-related expenses for continuing exploration and production operations during the six months ended June 30, 2016 and 2015 and the last three years are shown in the following table.

(Millions of dollars)	Six Months Ended June 30, 2016	2015	2015	2014	2013
Lease operating expense	$ 315.6	$ 459.9	$ 832.3	$ 1,089.9	$ 1,252.9
Severance and ad valorem taxes	26.1	39.9	65.8	107.2	87.3
Depreciation, depletion and amortization	533.7	880.2	1,607.9	1,897.5	1,543.6
Total	$ 875.4	$ 1380.0	$ 2,506.0	3,094.6	2,883.8

Cost per equivalent barrel sold for these production-related expenses are shown by geographical area in the following table.

(Dollars per equivalent barrel)	Six Months Ended June 30, 2016	2015	2015	2014	2013
United States Eagle Ford Shale					
Lease operating expense	$ 8.57	$ 12.21	$ 10.27	$ 11.25	$ 11.15
Severance and ad valorem taxes	2.27	3.04	2.50	4.64	5.39
Depreciation, depletion and amortization (DD&A) expense	25.10	27.06	26.71	27.87	30.48
United States Gulf of Mexico					
Lease operating expense	8.93	9.86	9.42	11.73	17.28
DD&A expense	24.08	22.25	22.60	27.47	21.32
Canada Conventional operations					
Lease operating expense	5.06	6.91	6.18	10.37	10.50
Severance and ad valorem taxes	0.26	0.32	0.29	0.36	0.29
DD&A expense	10.80	14.15	12.74	17.00	18.58
Canada Synthetic oil operations					
Lease operating expense	41.15	42.36	38.88	53.39	47.47
Severance and ad valorem taxes	1.46	1.34	1.20	1.16	1.04
DD&A expense	9.72	12.30	11.90	12.32	11.79
Malaysia					
Lease operating expense Sarawak	6.25	8.73	7.82	7.91	9.43
Block K	12.95	13.25	13.20	15.04	14.30
DD&A expense Sarawak	9.60	23.15	18.78	20.30	14.01
Block K	12.35	30.96	26.25	26.79	22.21
Total oil and gas operations					
Lease operating expense	9.64	11.97	10.87	13.31	16.66
Severance and ad valorem taxes	0.80	1.04	0.86	1.31	1.16
DD&A expense	16.30	22.90	21.00	23.16	20.53

2015 versus 2014

Lease operating expenses totaled $832.3 million in 2015, compared to $1,089.9 million in 2014. Lease operating expense per equivalent barrel in the Eagle Ford Shale decreased nearly $1.00 on a per-unit basis due to lower service costs, cost-saving initiatives and higher volume produced. Gulf of Mexico cost per barrel declined $2.31 per equivalent barrel due to lower fixed charges for third party processing facility at Thunder Hawk, additional third-party cost sharing at the Thunder Hawk and Front Runner fields, cost saving initiatives, and lower major repairs, partially offset by lower volumes produced. Lease operating expense for conventional operations in Canada improved in 2015 due to lower costs in the Seal heavy oil area, increased cost sharing for third party processing in the Tupper area and a lower Canadian dollar exchange rate. Synthetic oil operations costs per barrel decreased by $14.51 per barrel primarily due to lower Canadian dollar exchange rate, cost savings efforts and lower power costs. Operating expense in Block K decreased by $1.84 on a per-unit basis and benefited from higher volumes produced at the main Kakap field.

Severance and ad valorem taxes totaled $65.8 million in 2015 and $107.2 million in 2014. Severance and ad valorem taxes in the United States in 2015 were lower primarily due to weaker average commodity prices in the Eagle Ford Shale.

Depreciation, depletion and amortization expense for continuing exploration and production operations totaled $1,607.9 million in 2015 and $1,897.5 million in 2014. The $289.6 million decrease in 2015 compared to 2014 was primarily due to lower per-unit capital amortization rates and lower oil and natural gas volume sold. Eagle Ford Shale rate per equivalent barrel decreased due to reserve additions and cost improvements on 2015 drilling activities. The unit cost in the Gulf of Mexico decreased due to reserve additions, mix of production and lower unit rates due to impairment of assets. Canada conventional operations rate per barrel of oil equivalent decreased in 2015 due to a lower Canadian dollar exchange rate, higher mix of production from the Tupper area and impairment of the Seal heavy oil field. Depreciation per barrel in Sarawak improved in 2015 due to mix of production and the impairment of assets.

2014 versus 2013

Lease operating expenses totaled $1,089.9 million in 2014 and $1,252.9 million in 2013. Lease operating expense per equivalent barrel in the Eagle Ford Shale was essentially flat in 2014 and 2013, while cost per barrel in the Gulf of Mexico declined in 2014 primarily due to higher production related to start-up of the Dalmatian field and lower fixed charges for a third party processing facility at Thunder Hawk. Lease operating expense for conventional operations in Canada was down slightly in 2014 due mostly to a lower Canadian dollar exchange rate. Lease operating expense per barrel for synthetic oil operations rose in 2014 compared to the prior year due to a combination of lower net production and higher maintenance and power costs. Lease operating expense for Sarawak oil and gas operations declined in 2014 per barrel due to higher full-year 2014 volumes produced at oil fields which started up during 2013. Block K operations had higher lease operating expense per barrel in 2014 due to overall lower production, but with a benefit from start-up of the main Kakap field in the second half of the year.

Severance and ad valorem taxes totaled $107.2 million in 2014 and $87.3 million in 2013. On a per barrel equivalent basis, Eagle Ford Shale production taxes were less in 2014 than 2013 due to a lower mix of production value primarily caused by a larger increase in growth of lower value natural gas liquids in this area.

Depreciation, depletion and amortization expense for continuing exploration and production operations totaled $1,897.5 million in 2014 and $1,543.6 million in 2013. The $353.9 million increase in 2014 compared to 2013 was attributable to added production in areas that carried a higher overall capital amortization cost in 2014, in particular at Eagle Ford Shale, Dalmatian, Kakap main field and Siakap. The rate per equivalent barrel in 2014 at Eagle Ford Shale declined due to the timing of reserves migration to the proved category and cost improvements achieved on later drilling activities. The per barrel cost in the Gulf of Mexico increased in 2014 due to start-up of the Dalmatian field where costs early in the life of the field exceed the U.S. average due to the timing of migration of reserves to the proved category. Canada conventional cost per barrel declined in 2014 mostly due to a lower Canadian dollar exchange rate compared to 2013. Synthetic oil operations had a higher per barrel cost in 2014 due to straight-line depreciation costs for certain processing facilities being expensed over fewer production barrels. Depreciation per barrel rose in 2014 for both Sarawak and Block K areas due to new field production carrying a higher capital amortization cost per unit compared to the more mature fields in these areas.

Exploration expenses for continuing operations for each of the six months ended June 30, 2016 and 2015 and the last three years are shown in total in the following table, and amounts are reported by major operating area on pages F-59 and F-60 of the financial statements included elsewhere and incorporated by reference in this prospectus supplement and the accompanying prospectus. Expenses other than undeveloped lease amortization are included in the capital expenditures total for exploration and production activities.

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(Millions of dollars)	Six Months Ended June 30, 2016	2015	2015	2014	2013
Dry holes	$ 14.3	$ 99.0	$ 296.8	$ 270.0	$ 262.9
Geological and geophysical	8.3	23.5	49.9	99.5	117.5
Other	16.0	25.4	48.8	69.7	54.9
	38.6	147.9	395.5	439.2	435.3
Undeveloped lease amortization	25.4	45.8	75.4	74.4	66.9
Total exploration expenses	$ 64.0	$ 193.7	$ 470.9	$ 513.6	$ 502.2

2015 versus 2014

Dry hole expense in 2015 was $26.8 million more than 2014 primarily due to expensing of wells in the Gulf of Mexico, Australia and Malaysia. Dry hole costs in the Gulf of Mexico of $241.3 million were attributable to three unsuccessful wells in Mississippi Canyon and one well in Walker Ridge. Dry hole costs in Malaysia of $29.7 million related to unsuccessful wildcat drilling in Blocks SK 2C and H. Dry hole cost in other foreign areas of $25.8 million is attributable to three unsuccessful wells in Block WA-481-P in Australia. Geological and geophysical (G&G) expense was $49.6 million lower in 2015 primarily due to reduced spending in Namibia, Equatorial Guinea, Vietnam and Gulf of Mexico. Other exploratory costs of $48.8 million in 2015 was down $20.9 million compared to 2014. Exploration staff and office costs around the world were lower together with non-recurring costs in 2014 related to both a charge-off of shared drilling equipment improvement costs for a third-party rig that was released and a penalty associated with not drilling on a license in Indonesia.

Impairment expense in 2015 for E&P operations exceeded 2014 by $2,441.9 million. The 2015 included significant noncash impairment expense of $2,493.2 million before tax and $1,660.0 million after-tax for producing heavy oil properties in Western Canada, producing offshore properties in Malaysia, and producing and non- producing properties in the Gulf of Mexico. The 2015 impairments were the result of significant declines in current and future crude oil prices since the end of 2014.

The exploration and production business recorded expenses of $48.7 million in 2015 and $50.8 million in 2014 for accretion on discounted abandonment liabilities. Because the liability for future abandonment of wells and other facilities is carried on the balance sheet at a discounted fair value, accretion must be recorded annually so that the liability will be recorded at full value at the projected time of abandonment. The $2.1 million decrease in 2015 primarily related to lower abandonment liabilities following the sale of 30% interest in Malaysia assets and a lower Canadian dollar exchange rate.

The effective income tax rate for exploration and production continuing operations was 35.6% in 2015 and 19.4% in 2014. The effective tax rate in 2015 was above the tax rate in 2014 and near the statutory U.S. tax rate of 35.0%. The 2014 period included several items discussed below that didn t reoccur in 2015. Through 2015, no tax benefits have thus far been recognized for costs incurred for Blocks PM 311/312, offshore Peninsular Malaysia, and Block SK 314A and Block SK 2C offshore Sarawak, Malaysia.

At December 31, 2015, 113.0 million barrels of the Company s U.S. crude oil proved reserves, 14.7 million barrels of U.S. NGL proved reserves and 84.1 billion cubic feet of U.S. natural gas proved reserves were undeveloped. Total proved undeveloped reserves represent 38% of total proved reserves on a barrel of oil equivalent basis as of December 31, 2015. Approximately 94% of the total U.S. undeveloped reserves (on a barrel of oil equivalent basis) are associated with the Company s Eagle Ford Shale operations in South Texas. Further drilling and facility construction are generally required to move the undeveloped reserves in the Eagle Ford Shale area to developed. The deepwaters of the Gulf of Mexico accounted for the remaining 6% of proved undeveloped reserves at December 31, 2015. In the Western Canadian Sedimentary Basin, undeveloped natural gas proved reserves totaled 456.1 billion cubic feet, with the migration of these reserves, primarily in the Tupper and Tupper West areas, dependent on both development drilling and completion of processing and transportation facilities. In Block K Malaysia, oil proved undeveloped reserves of 9.6 million barrels are primarily at the Kikeh field, where undeveloped proved oil reserves are subject to further drilling before being moved to developed. Also in Malaysia, there were billion cubic feet of undeveloped natural gas proved reserves at various offshore fields at year-end 2015. These undeveloped natural gas reserves in Malaysia are mainly associated with Block H, where a development project commenced following sanction in 2014. On a worldwide basis, the Company spent approximately $1.74 billion in 2015, $3.21 billion in 2014 and $3.40 billion in 2013 to develop proved reserves.

2014 versus 2013

Dry hole expense in 2014 was $7.1 million more than in 2013 primarily due to expensing prior-year wells in Malaysia and the Gulf of Mexico that had been previously suspended while development options were studied. Dry hole costs in Malaysia of $47.4 million for these wells were attributable to government denial of a request to extend a gas holding period for Block PM 311, while the previously suspended Gulf of Mexico dry hole for $18.8 million was caused by low year-end 2014 natural gas prices. The 2014 costs also included $103.9 million for an unsuccessful well in Cameroon. These higher 2014 costs were partially offset by the costs of unsuccessful exploration drilling conducted in Australia in 2013.

G&G expense was $18.0 million lower in 2014 due to less spending in 2014 for seismic data covering exploration prospects in Southeast Asia. Other exploratory costs were up $14.8 million in 2014 due to higher exploration staff and office costs in Southeast Asia, a charge-off in 2014 of shared drilling equipment improvement costs for a third-party rig that was released, and a penalty associated with an exploration well that was not drilled on a license in Indonesia. Undeveloped lease amortization increased $7.5 million primarily due to higher amortization related to remote unproved lease acreage released in the Eagle Ford Shale, but partially offset by no repeat in 2014 of lease costs written off in 2013 in the Kurdistan region of Iraq.

Impairment expense in 2014 for E&P operations exceeded 2013 by 29.7 million. The 2014 year charge included write-off of goodwill recorded in a business acquisition in Western Canada in 2000, and a writedown of one natural gas field in the Gulf of Mexico. Both charges in 2014 were required due to the weakness in oil and natural gas prices, which retreated severely in late 2014. The exploration and production business recorded expenses of $50.8 million in 2014 and $49.0 million in 2013 for accretion on discounted abandonment liabilities. The $1.8 million increase in 2014 primarily related to development wells added in the Gulf of Mexico during the year.

The effective income tax rate for exploration and production continuing operations was 19.4% in 2014 and 38.9% in 2013. The effective tax rate in 2014 was well below the tax rates in 2013 and the statutory U.S. tax rate of 35.0% due primarily to tax benefits in foreign areas during 2014. With the sale of 20% of the assets in Malaysia near year-end 2014, the purchaser assumed certain future Malaysian tax obligations, which essentially reduced the Company s deferred tax liabilities by $176.6 million. Additionally, the Company recognized a $65.4 million tax benefit during 2014 for past exploratory expenses incurred in Block H, where proved reserves were added at year-end 2014 related to a new field development plan. Also, in 2014 the Company recognized U.S. income tax benefits of $95.9 million associated with investments in exploration operations in Cameroon, the Kurdistan region of Iraq, and one block in Australia, in areas where the Company is exiting. Tax jurisdictions with no current tax benefit on expenses primarily include certain non-revenue generating areas in Malaysia as well as other foreign exploration areas in which the Company operates. Each main exploration area in Malaysia is currently considered a distinct taxable entity and expenses in certain areas may not be used to offset revenues generated in other areas.

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Refining and Marketing The Company has now transitioned to a fully independent oil and gas exploration and production company. Murphy formerly had a significant U.S. and U.K. refining and marketing business. On August 30, 2013, the Company spun-off to shareholders its U.S. retail marketing business. The now separate, publicly traded U.S. retail company named Murphy USA Inc. is listed on the New York Stock Exchange under the symbol MUSA . On September 30, 2014, Murphy Oil sold its U.K. retail marketing business. In late 2014, the Company decided to decommission and abandon the Milford Haven, Wales refinery. The Company sold the remainder of its U.K. downstream assets in June 2015. Both the U.S. and U.K. downstream businesses are reported as discontinued operations for all periods presented. Further discussion of the results of discontinued operations is included below.

Corporate

Six months ended June 30, 2016 versus six months ended June 30, 2015

For the first half of 2016, corporate activities reflected net costs of $72.2 million compared to net costs of $53.0 million a year ago. The $19.2 million increase in net cost in the current year is primarily due to lower foreign currency exchange benefits and higher net interest cost. An after-tax gain of $21.3 million occurred in 2016 on transactions denominated in foreign currencies compared to an after-tax gain of $35.1 million a year ago.

2015 versus 2014

The after-tax costs of corporate activities, which include interest income and expense, foreign exchange effects, and corporate overhead not allocated to operating functions were $244.9 million in 2015, $164.8 million in 2014 and $140.7 million in 2013.

The net costs of Corporate activities in 2015 were unfavorable to 2014 by $80.1 million mostly due to higher tax expense related to a U.S deferred tax charge of $188.5 million associated with a $2.0 billion distribution from a foreign subsidiary, partially offset by higher foreign currency exchange gains and lower administrative costs. Interest income was $3.7 million unfavorable in 2015 compared to 2014 due to lower average invested cash balances in Canada. The after-tax effects of foreign currency exchange was a gain of $86.7 million in 2015, $46.8 million higher than in 2014. These effects arose due to transactions denominated in currencies other than the respective operations predominant functional currency. The foreign currency gain recognized in 2015 was mostly realized in Malaysia, where a weaker Malaysian ringgit in 2015 led to a benefit from lower income tax obligations payable in local currency. The Malaysian operation s functional currency is the U.S. dollar. Administrative expenses associated with corporate activities were lower in 2015 by $22.4 million, primarily due to lower employee compensation expense. Depreciation expense was $3.2 million higher in 2015 compared to 2014 due to depreciation of certain obsolete assets and installation of new software. Total provision for income taxes was higher in 2015 compared to 2014 by $142.9 million due primarily to the aforementioned deferred tax on a foreign distribution, partially offset by benefits related to changes in prior-year estimated taxes following the filing of the 2014 tax return.

2014 versus 2013

The after-tax costs of corporate activities were $164.8 million in 2014 and $140.7 million in 2013. The net cost of Corporate activities in 2014 exceeded 2013 by $24.1 million, primarily due to higher net interest expense and lower profits on foreign currency exchange, but somewhat offset by lower administrative expenses. Interest income was $3.8 million higher in 2014 than 2013 due to larger average invested cash balances in Canada and interest earned on Canadian prior-year tax installments. Net interest expense, after capitalization of finance-related costs to development projects, was higher by $43.9 million in 2014 compared to the prior year due to larger average borrowing levels in 2014 and lower amounts of interest capitalized to development projects.

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Administrative expenses associated with corporate activities were lower in 2014 by $56.3 million, primarily due to nonrecurring expenses incurred in 2013 related to consulting and staffing for the U.S. retail marketing operations that was spun-off to shareholders in August 2013. The after-tax effects of foreign currency exchange was a gain of $39.9 million in 2014, but $30.4 million lower than in 2013. The foreign currency gain recognized in 2014 was mostly realized in Malaysia, where a significantly weaker Malaysian ringgit in 2014 led to a benefit from lower income tax obligations payable in the local currency. However, the foreign currency gain variance in 2014 compared to the prior year was primarily related to the U.K. as an unfavorable earnings effect from the British pound sterling exchange rate in 2014 followed a favorable effect in 2013. Income tax benefits in 2014 for corporate activities were $13.4 million less than the prior year.

Discontinued Operations The Company has presented a number of businesses as discontinued operations in its consolidated financial statements. These businesses principally include:

- U.S. retail marketing operations spun-off to shareholders on August 30, 2013. Results of operations are included in the Company s financial statements through the date of spin-off.

- U.K. refining and marketing operations (R&M). The Company decommissioned the Milford Haven refinery units and completed the sale of its remaining downstream assets in the U.K. in the second quarter of 2015 for cash proceeds of $5.5 million. The Company has accounted for the U.K. downstream business as discontinued operations for all periods presented.

- U.K. oil and gas assets sold through a series of transactions in the first half of 2013. The Company s financial statements include the results of operations through the respective dates the asset were sold, plus the cumulative gain realized upon sale.

The results of these discontinued operations for the six months ended June 30, 2016 and 2015 and the last three years are reflected in the following table.

	Six Months Ended June 30,				
(Millions of dollars)	**2016**	**2015**	**2015**	**2014**	**2013**
U.S. refining and marketing	$	$	$		134.8
U.K. refining and marketing	(0.1)	(2.6)	(14.8)	(120.6)	(119.2)
U.K. exploration and production	0.8	(0.2)	(0.2)	1.2	219.8
Income (loss) from discontinued operations	$ 0.7	$ (2.8)	$ (15.0)	(119.4)	235.4

Six months ended June 30, 2016 versus six months ended June 30, 2015

The Company has presented all operations in the U.K. as discontinued operations in its consolidated financial statements. In June 2015, the Company completed an agreement to sell the remaining U.K. downstream assets.

2015 versus 2014

The loss from U.K. refining and marketing (R&M) operations of $14.8 million was primarily related to loss on sale of assets, employee severance costs, legal fees and other abandonment costs related to closure. The Company sold the finished product terminal operations during 2015 for cash proceeds of $5.5 million. Certain costs to be paid in 2016 or beyond relate to future services and will be recognized over the applicable service period.

2014 versus 2013

The loss from U.K. R&M operations of $120.6 million in 2014 was similar to the loss in 2013. The Company sold the retail marketing fueling stations during 2014 with an associated gain of $101.7 million. Total proceeds from

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the sale of the retail marketing assets were $212.0 million. The Milford Haven, Wales refinery ceased processing crude oil in May 2014. This refining operation incurred an impairment charge of $269.2 million in 2014, along with losses from operations and costs related to employee severance and other abandonment activities, which were partially offset by inventory profits arising from the sale of most of the refinery s inventory.

Capital Expenditures

Capital expenditures from continuing operations, including exploration expenditures, were $463.6 and $ 1,145.1 for the six months ended June 30, 2016 and 2015, respectively, and $2.19 billion in 2015, $3.76 billion in 2014 and $3.97 billion in 2013. These amounts excluded capital expenditures of $0.2 million in 2015, $12.3 million in 2014, $154.6 million in 2013 related to discontinued operations, which were associated with U.K. R&M operations that were either sold or shuttered at the end of 2014, U.S. retail marketing operations spun-off in August 2013, and U.K. oil and gas assets sold in the first half of 2013. Capital expenditures included $395.5 million, $439.2 million and $435.3 million, respectively, in 2015, 2014 and 2013 for exploration costs that were expensed.

Capital expenditures for exploration and production continuing operations totaled $442.9 and $1,119.5 for the six months ended June 30, 2016 and 2015, respectively, and $2.13 billion in 2015, $3.74 billion in 2014 and $3.94 billion in 2013.

The reduction in capital expenditures in the exploration and production business in 2016 compared to 2015 was primarily attributable to lower development drilling in the Eagle Ford Shale area in the United States and offshore Malaysia and lower spending on exploration drilling in the Gulf of Mexico and other international operations. The 2016 capital expenditures included $206 million to fund acquisition of Kaybob Duvernay and liquids rich Montney lands in Canada.

E&P capital expenditures in 2015 included $12.6 million for lease acquisitions principally in the U.S., $371.9 million for exploration activities, and $1.74 billion for oil and gas project developments. U.S. lease acquisitions included acreage extensions in the Eagle Ford Shale as well as new leases acquired in the Gulf of Mexico. Exploration activities included drilling wells in the Gulf of Mexico, Malaysia, Australia and Vietnam. Additionally, exploration activities included seismic acquisition in the Gulf of Mexico and other areas, primarily related to prospects in Australia and Southeast Asia. Development capital expenditures in 2015 included $830.2 million for the drilling and completion program in the Eagle Ford Shale; $508.6 million for Gulf of Mexico development activities including Kodiak and Dalmatian South; $116.5 million for development work in the Western Canadian Sedimentary Basin; $23.6 million for the Syncrude project; $41.7 million combined for Hibernia and Terra Nova; $67.8 million for development projects in deepwater Malaysia, including Kikeh, Kakap and Siakap; $144.3 million for oil and natural gas projects offshore Sarawak Malaysia; and $23.8 million for development of a Floating Liquefied Natural Gas project for Block H Malaysia.

E&P capital expenditures in 2014 included $92.9 million for U.S. lease acquisitions, $430.1 million for exploration activities, and $3.21 billion for oil and gas project developments. U.S. lease acquisitions included acreage extensions in the Eagle Ford Shale as well as new leases acquired in the Gulf of Mexico. Exploration activities included drilling wells in the Gulf of Mexico, Cameroon, Indonesia and Vietnam. Additionally, exploration activities included seismic acquisition in the Gulf of Mexico and other areas, primarily related to prospects in Southeast Asia and West Africa. Development capital expenditures in 2014 included $1.52 billion for the drilling and completion program in the Eagle Ford Shale; $373.7 million for Gulf of Mexico development activities; $286.0 million for development work in the Western Canadian Sedimentary Basin; $92.5 million for the Syncrude project; $64.5 million combined for Hibernia and Terra Nova; $562.9 million for development projects in deepwater Malaysia, including Kikeh, Kakap and Siakap; and $299.3 million for oil and natural gas projects offshore Sarawak Malaysia.

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E&P capital expenditures in 2013 included $35.6 million for lease acquisitions, $493.5 million for exploration activities, and $3.41 billion for development projects. Lease acquisitions were primarily related to acreage extensions in the Eagle Ford Shale area. Exploration activities included exploratory drilling primarily in the Gulf of Mexico, Australia, Cameroon and Brunei. Exploratory activities also included seismic and other geophysical costs primarily in the U.S., Australia, Indonesia, Vietnam and West Africa. Development expenditures in 2013 included $1.48 billion for the drilling and completion program in the Eagle Ford Shale; $230.9 million for fields in the Gulf of Mexico, including Dalmatian, which started up in 2014; $156.7 million for synthetic oil operations; $140.4 million for heavy oil at Seal; $283.5 million for Kikeh; $136.7 million for Kakap-Gumusut; $214.6 million for Siakap North-Petai; $681.3 million for Sarawak oil fields; and $49.6 million for Hibernia and Terra Nova, offshore Newfoundland.

Exploration and production capital expenditures are shown by major operating area on page F-58 of the financial statements included elsewhere and incorporated by reference in this prospectus supplement and the accompanying prospectus.

Capital expenditures for discontinued operations included $114.3 million in 2013 for U.S. retail marketing operations, which primarily included station construction and other improvements in each year. U.K. refining and marketing operations had capital expenditures during the years ended December 31, 2014 and 2013 of $12.3 million and $32.2 million, respectively. U.K. E&P operations had capital expenditure of $8.1 million in 2013.

Cash Flows

Operating activities

Net cash provided by continuing operating activities was $113.4 million for the first six-months of 2016 compared to $715.2 million during the same period in 2015. The decline in cash provided by continuing operations activities in 2016 was primarily attributable to significantly lower realized sales prices for the Company s oil and gas production and lower volume sold during the current year, offset in part by lower lease operating expenses. Changes in noncash operating working capital from continuing operations used cash of $86.8 million during the first six-months of 2016, compared to generating cash of $107.2 million in 2015. The use of cash in 2016 included $261.8 million associated with pay-off of cancelled deepwater rig contracts that were previously charged to expense in 2015.

Cash provided by operating activities of continuing operations was $1.18 billion in 2015, $3.05 billion in 2014 and $3.21 billion in 2013. Cash flows associated with formerly owned U.S. downstream, U.K. oil and gas production businesses and U.K. downstream businesses have been classified as discontinued operations in the Company s consolidated financial statements. Cash flow provided by continuing operations was $1.87 billion lower in 2015 than in 2014 due to generally weaker crude oil and natural gas sales prices in 2015, partially offset by lower lease operating expenses and lower severance and ad valorem taxes. Cash flow provided by continuing operations was $162.1 million lower in 2014 compared to 2013. The decrease in 2014 was attributable to lower crude oil sales prices plus higher payments for interest and income taxes compared to the prior year. Cash provided by operating activities was reduced by expenditures for abandonment of oil and gas properties totaling $13.4 million in 2015, $36.8 million in 2014 and $51.6 million in 2013. Operating cash flows were reduced by payments of income taxes of $118.7 million in 2015, $573.8 million in 2014 and $457.0 million in 2013. The total reductions of operating cash flows for interest paid during the three years ended December 31, 2015, 2014 and 2013 were $117.7 million, $134.8 million and $113.0 million, respectively.

Investing activities

Proceeds from sales of property and equipment generated cash of $1,153.3 million in 2016 compared to $423.1 million in 2015. The 2016 proceeds are mainly attributable to the sale of the Company s non-operated

5% interest in Syncrude Canada Ltd. (Syncrude) for $739.1 million and the disposition of certain midstream assets in the Tupper area of Western Canada for $414.1 million. The prior year amount primarily related to proceeds received upon sale of a 10% interest in Malaysian assets. The uses of cash for property additions and dry holes, which including amounts expensed, were $604.6 million and $1,433.6 million in the six-month period ended June 30, 2016 and 2015, respectively.

Capital expenditures of the exploration and production business represent the most significant component of investing activities. Property additions and dry hole costs for continuing operations used cash of $2.55 billion in 2015, $3.68 billion in 2014 and $3.59 billion in 2013. Cash of $911.8 million, $986.3 million and $923.5 million was spent in 2015, 2014 and 2013, respectively, to acquire Canadian government securities with maturities greater than 90 days at the time of purchase. Proceeds from maturities or sales of Canadian government securities with maturities greater than 90 days at date of acquisition were $1,129.1 million in 2015, $899.9 million in 2014 and $664.3 million in 2013. Proceeds from sales of assets generated cash of $423.9 million in 2015, $1.47 billion in 2014 and $1.7 million in 2013. The 2015 and 2014 proceeds primarily arose due to sale of 30% of the Company s oil and gas assets in Malaysia.

Financing activities

A significant source of cash included $701.4 million in the 2016 period and $663.3 million in 2015 from maturity of Canadian government securities that had maturity dates greater than 90 days at acquisition. The Company borrowed $823.0 million in the 2015 period to fund capital expenditures and repurchase Company stock.

Total cash dividends to shareholders amounted to $120.5 million in 2016 and $124.6 million in 2015. In the first six months of 2015, the Company expended $250.0 million to acquire 5,236,709 shares of Common stock. Also, the purchase of Canadian government securities with maturity dates greater than 90 days at acquisition used cash of $651.2 million in the 2016 period and $629.8 million in the 2015 period. The Company repaid debt in the amount of $600.0 million in the six-month period of 2016. The debt repayment was funded using proceeds from the sale of assets. The Company had no borrowings outstanding on its $2.0 billion revolving credit facility at June 30, 2016. The Company used $450.0 million of cash in the 2015 period to repay current maturities of long-term debt.

During 2015, the Company borrowed $600.0 million under bank financing arrangements. The Company used $450.0 million cash during 2015 to repay current maturities of long-term debt. Funds from Malaysia and the U.K., which were repatriated to the U.S., tempered the Company s net borrowings during the just completed year, as the majority of these funds were used to pay down long-term debt before year-end 2015. The Company paid $250.0 million in 2015, $375.0 million in 2014 and $500.0 million in 2013 to repurchase 5.97 million shares, 6.37 million shares and 7.86 million shares, respectively, of its Common stock. Cash used for dividends to stockholders was $245.0 million in 2015, $236.4 million in 2014 and $235.1 million in 2013. The Company increased its normal dividend rate by 12% in 2014 as the annualized dividend was raised from $1.25 per share to $1.40 per share effective in the third quarter 2014. There was no change in the dividend rate during 2015. At the date of the spin-off in 2013, Murphy USA Inc. paid Murphy Oil Corporation cash of $650.0 million, which the Company primarily used to partially repay outstanding debt. In 2015, 2014 and 2013, cash of $9.0 million, $6.8 million and $16.7 million, respectively, was used to pay statutory withholding taxes on stock-based incentive awards that vested with a net-of-tax payout.

Discontinued operations

The Company s discontinued operations in the U.K. and U.S. required operating cash flow of $15.0 million in 2015 and $39.6 million in 2014, but provided cash flow of $427.8 million in 2013. The 2015 activities primarily related to the U.K. terminal operations which were sold in June 2015. The 2014 period included the U.K. refining

and marketing activities which had poor refining margins prior to shutdown of the refinery at Milford Haven in May 2014. The 2013 period included positive operating cash flow from the U.S. retail marketing operations that were spun off to shareholders on August 30, 2013. In 2015, the sale of U.K. terminal assets generated cash of $5.0 million, and in 2014, the sale of U.K. retail marketing assets generated cash of $212.0 million. In 2013, the sale of all U.K. oil and gas assets generated cash of $282.2 million. In connection with the sales of the various U.K. assets, the Company repatriated cash from the U.K. of $184 million in 2015; $250 million in 2014; and $240 million in 2013. Cash utilized for other investing activities of discontinued operations totaled $12.5 million in 2014 and $165.7 million in 2013 and these mostly related to cash payments for capital expenditures. At December 31, 2015, the Company s U.K. discontinued operations had cash of $7.9 million. This cash is classified within Current assets held for sale on the Consolidated Balance Sheet at year-end 2015, effectively removing this amount from the Company s reported cash balance. This cash balance was $192.6 million lower than the cash balance of $200.5 million classified as held for sale as of December 31, 2014, primarily due to repatriation of $184 million during 2015.

Financial Condition

Cash and invested cash are maintained in several operating locations outside the United States. At June 30, 2016, cash, cash equivalents and cash temporarily invested in Canadian government securities held outside the U.S. included U.S. dollar equivalents of approximately $188.7 million in Canada and $81.4 million in Malaysia. In certain cases, the Company could incur taxes or other costs should these cash balances be repatriated to the U.S. in future periods. This could occur due to withholding taxes and/or potential additional U.S. tax burden when less than the U.S. Federal tax rate of 35% has been paid for cash taxes in foreign locations. A lower cash tax rate is often paid in foreign countries in the early years of operations when accelerated tax deductions are permitted to spur oil and gas investments; cash tax rates are generally higher in later years after accelerated tax deductions in early years are exhausted. Canada collects a 5% withholding tax on any cash repatriated to the United States through a dividend to the U.S. parent.

Working capital (total current assets less total current liabilities) at June 30, 2016 was $157.1 million, $383.3 million more than December 31, 2015, with the increase attributable to lower accounts payable for deepwater rig contract exit cost and other operating activities. Working capital amounted to a deficit of $226.2 million at year-end 2015. Total working capital declined in 2015 due to a partial paydown of long-term debt with available cash proceeds plus a significant current liability recorded for exit of deepwater rig contracts at the end of the year. The Company had working capital of $131.3 million at year-end 2014. Cash and cash equivalents at the end of 2015 totaled $283.2 million compared to $1.19 billion at year-end 2014. As described in the following paragraph, a portion of this cash held at year-end 2014 was used to pay down $450.0 million current maturities of long-term debt in January 2015. In addition to the Company s cash position, it held short-term investments in Canadian government treasury securities of $173.3 million at year-end 2015, down $288.0 million compared to 2014. These short-term investments decreased in 2015 primarily due to an intercompany loan to an affiliated company and a lower Canadian exchange rate. These slightly longer-term Canadian investments were purchased in each year because of a tight supply of shorter-term securities available for purchase in Canada. These short-term Canadian government investments could quickly be converted to cash if a need for funds in Canada arise.

At June 30, 2016, long-term debt of $2,435.5 million had decreased by $605.1 million compared to December 31, 2015. Long-term debt was paid down in 2016 using part of the sales proceeds from Canadian asset disposition.

Long-term debt at year-end 2015 was $522.9 million higher than year-end 2014. The increase in debt in 2015 was primarily due to capital expenditures, share buyback and cash dividends, which in total exceeded cash generated from operating activities. At December 31, 2015, long-term debt represented 36.4% of total capital employed. Long-term debt at year-end 2014 was $400 million lower than year-end 2013. The debt reduction in

2014 was achieved by using most of the proceeds from a 20% sale of oil and gas assets in Malaysia to repay debt. Prior to the Malaysia sale in December 2014, long-term debt had risen in 2014 due to a combination of capital expenditures, share buyback and cash dividends, which in total exceeded cash generated from operating activities. At December 31, 2014, long-term debt represented 22.8% of total capital employed. Also, at December 31, 2014, current maturities of long-term debt included $450.0 million of loans that were repaid on January 15, 2015 with proceeds from the sale of Malaysian assets. Stockholders equity was $5.31 billion at the end of 2015, $8.57 billion at the end of 2014 and $8.60 billion at the end of 2013. Stockholders equity declined in 2015 primarily due to impairments of assets, lower commodity prices, $250.0 million of Common stock repurchases during the year and a reduction in the foreign currency translation balance due to a weaker Canadian dollar against the U.S. dollar during the year. Stockholders equity declined in 2014 primarily due to a total of $375.0 million of Common stock repurchases during the year coupled with a reduction in the balance of foreign currency translation due to a weakening of the Canadian dollar against the U.S. dollar during the year.

Other significant changes in Murphy s year-end 2015 balance sheet compared to 2014 included a $350.6 million decrease in accounts receivable, primarily caused by lower overall average realized sales prices at year-end 2015 compared to 2014 and the completion of the sale of 10% interest in Malaysian properties. Inventory values were $75.9 million less at year-end 2015 than in 2014 mostly due to 10% sale of Malaysian properties in January 2015. Current assets held for sale amounted to $38.3 million at December 31, 2015 and $376.1 million at December 31, 2014. The year-end 2015 amount primarily included cash held by the U.K. downstream business, amounts receivable for sales of scrap metal and other materials as the refinery is dismantled and a short-term tax receivable expected to be collected in 2016. Net property, plant and equipment decreased by $3.5 billion in 2015 primarily due to impairments of assets and the disposition of 10% of Malaysia oil and gas assets in January 2015. Deferred charges and other assets increased $164.4 million in 2015 due primarily to a net deferred tax asset position in Malaysia and the U.S. as compared to a net deferred tax liability position in 2014. Assets held for sale-noncurrent decreased by $51.0 million in 2015 primarily related to disposition of the remaining U.K. downstream assets in 2015. Current maturities of long-term debt at year-end 2015 was $446.5 million lower than at the prior year-end due to payment of a short-term debt obligation of $450.0 million in January 2015.

Accounts payable decreased by $746.0 million at year-end 2015 compared to 2014 primarily due to liabilities assumed by the purchaser of 10% of the Company s oil and gas assets in Malaysia and lower overall costs as capital expenditures were significantly reduced due to the low commodity price environment. Income taxes payable was $54.2 million lower at year-end 2015 than at the end of 2014, primarily due to tax payments in Malaysia in 2015 and lower profits. Other taxes payable decreased $14.0 million in 2015 primarily due to lower U.S. ad valorem and severance taxes owed. Current liabilities associated with assets held for sale of $7.3 million at December 31, 2015 decreased $144.3 million compared to the prior year-end primarily due to lower liabilities after sale of the remaining U.K. downstream assets in 2015, lower employee costs and lower refinery decommissioning costs.

Noncurrent deferred income tax liabilities were $954.1 million lower at year-end 2015 mostly due to impairment of assets and the assumption of certain future tax obligations by the purchaser of 10% of the Company s oil and gas assets in Malaysia in 2015. The noncurrent liability associated with future asset retirement obligations decreased by $48.1 million at year-end 2015 also mostly due to obligations assumed by the purchaser of Malaysian assets and revisions of prior estimates together with a lower Canadian dollar exchange rate that more than offset liabilities for new wells drilled in 2015. Noncurrent liabilities associated with assets held for sale at December 31, 2015 decreased by $8.3 million primarily due to disposition of the remaining U.K. refining and marketing business. Total stockholders equity of the Company decreased by $3.3 billion in 2015. A summary of transactions in stockholders equity accounts is presented in the Consolidated Statements of Stockholders Equity on page F-8 of the financial statements included elsewhere and incorporated by reference in this prospectus supplement and the accompanying prospectus.

Murphy had commitments for future capital projects of approximately $501.2 million at December 31, 2015. These commitments included $283.0 million for field development and future work in Malaysia, $109.8 million for work in the Eagle Ford Shale, $30.7 million for costs to develop deepwater Gulf of Mexico fields, and $45.2 million and $15.4 million for future work commitments offshore Vietnam and Brunei.

The primary sources of the Company s liquidity are internally generated funds, access to outside financing and working capital. The Company uses its internally generated funds to finance the major portion of its capital and other expenditures, but it also maintains lines of credit with banks and borrows as necessary to meet spending requirements. At December 31, 2015, the Company had access to a long-term committed credit facility in the amount of $2.0 billion with $600 million outstanding under the facility. The most restrictive of covenants under this committed credit facility limit the Company s long-term debt to capital ratio (as defined in the agreements) to 60%. The committed credit facility expires in May 2017 and a one and one-half year extension is currently being pursued. At December 31, 2015, the Company had uncommitted bank credit lines of approximately $300.0 million, but no borrowings were outstanding under these lines. The Company s ratio of long-term debt to total capital was 36.4% at year-end 2015.

In October 2015, the Company renewed its shelf registration statement on file with the Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities. The current shelf registration will expire in October 2018. Current financing arrangements are set forth more fully in Note F to the consolidated financial statements. Based on the anticipated level of 2016 capital expenditures for the Company, coupled with the current low price environment for crude oil and existing annual shareholder dividend levels, the Company anticipates that it will need to borrow funds under its long-term credit facility during 2016. The Company s earnings for the year ended December 31, 2015 were inadequate to cover fixed charges by $3.3 billion. The Company s ratio of earnings to fixed charges was 7.9 to 1 in 2014 and 9.5 to 1 in 2013.

Cash and invested cash are maintained in several operating locations outside the United States. At December 31, 2015, cash, cash equivalents and cash temporarily invested in Canadian government securities with greater than 90 day maturities held outside the U.S. included $235 million in Canada and $138 million in Malaysia. In addition, approximately $8 million of cash was held in the U.K. and has been classified as part of Assets held for sale in the Consolidated Balance Sheet at year-end 2015. In certain cases, the Company could incur cash taxes or other costs should these cash balances be repatriated to the U.S. in future periods. This could occur due to withholding taxes and/or potential additional U.S. tax burden when less than the U.S. tax rate of 35% has been paid for cash taxes in foreign locations. A lower cash tax rate is often paid in the U.S. and foreign countries in the early years of operations when accelerated tax deductions exist to incentivize oil and gas investments; cash tax rates are generally higher in later years after accelerated tax deductions in early years are exhausted. Canada collects a 5% withholding tax on any cash repatriated to the U.S. See Note I of the consolidated financial statements for further information regarding potential tax expense that could be incurred upon distribution of foreign earnings back to the United States.

Environmental Matters

Murphy faces various environmental and safety risks that are inherent in exploring for, developing and producing hydrocarbons. To help manage these risks, the Company has established a robust health, safety and environment governance program comprised of a worldwide policy, guiding principles, annual goals and a management system, with appropriate oversight at the business unit, senior leadership and board levels. The Company strives to minimize these risks by continually improving its processes through design, operation and maintenance, and through emergency and oil spill response planning to address any credible and major risks it identifies through impact assessments.

Murphy and other companies in the oil and gas industry are subject to numerous international, national, state, provincial and local environmental and safety laws and regulations. These requirements affect virtually all operations of the Company and increase Murphy s overall cost of business, including its capital costs to

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construct, maintain and upgrade equipment and facilities, and operating costs for ongoing compliance. Murphy allocates a portion of its capital expenditure program to comply with existing and anticipated environmental laws and regulations.

The principal environmental laws and regulations to which Murphy is subject address such matters as the generation, storage, handling, use, disposal and remediation of petroleum products, wastewater and hazardous materials, the emission and discharge of such materials to the environment, greenhouse gas emissions, wildlife, habitat and water protection and the placement, operation and decommissioning of production equipment. These laws and regulations also generally require permits for existing operations, as well as the construction or development of new operations. Any violation of applicable environmental laws, regulations or permits can give rise to significant civil and criminal penalties, injunctions, construction bans and delays, and other sanctions.

These laws, regulations and permits have been subject to frequent change and tended to become more stringent over time. For example, governmental initiatives have been implemented or are under development to regulate or further investigate the environmental impacts of hydraulic fracturing. In particular, the U.S. government has commenced a study to determine the environmental and health impacts of hydraulic fracturing and announced that it will propose standards for the treatment or disposal of wastewater from certain gas production operations.

In addition, certain jurisdictions in which the Company operates have required, or are considering requiring, more stringent permitting, chemical disclosure, transparency, water usage, disposal and well construction requirements. Regulators are also becoming increasingly focused on air emissions from the oil and gas industry, including volatile organic compound and methane emissions. For example, Alberta has announced regulations that would require Murphy s Seal facilities to conserve solution gas associated with primary recovery of heavy oil. In the United States, the Environmental Protection Agency has implemented requirements to reduce sulfur dioxide, volatile organic compound and hazardous air pollutant air emissions from oil and gas operations, including standards for wells that are hydraulically fractured. Any current or future air emission or other environmental requirements applicable to Murphy s businesses could curtail its operations or otherwise result in operational delays, liabilities and increased costs.

Murphy also could be subject to strict liability for environmental contamination, including with respect to its current or former properties, operations and waste disposal sites, or those of its predecessors. Contamination has been identified at certain of such sites as a result of which the Company may be required to remove or remediate previously disposed wastes, clean up contaminated soil, surface water and groundwater, address spills and leaks from pipelines and production equipment, and perform remedial plugging operations. In addition to significant investigation and remediation costs, such matters can also give rise to third party claims for fines, personal injury and property or other environmental damage.

Murphy allocates a portion of its capital expenditure program to comply with environmental laws and regulations, and such capital expenditures were approximately $46 million in 2015. This spending is projected to be approximately $9 million in 2016 with the reduction due to a scale back in expected overall capital project spending associated with low oil and gas prices.

Climate Change

Greenhouse gas emission regulation is becoming more stringent. Murphy is currently required to report greenhouse gas emissions from certain of its operations and, in British Columbia, is subject to a carbon tax on the purchase or use of virtually all carbon-based fuels. Under the U.S. Climate Action Plan, the Environmental Protection Agency is currently assessing how best to pursue methane emission reductions from the oil and gas sector, which process may result in further voluntary or mandated methane mitigation measures. Any limitation on or further regulation of, greenhouse gases, including through a cap-and-trade system, technology mandate, emissions tax, reporting requirement or other program, could restrict the Company s operations,

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curtail demand for hydrocarbons generally and/or impose increased costs, including to operate and maintain facilities, install pollution emission controls and administer and manage emissions trading programs.

Safety Matters

The Company is subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable foreign and state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in Murphy s operations and that this information be provided to employees, state and local government authorities and citizens. The Company believes that its operations are in substantial compliance with applicable safety requirements, including general industry standards, record-keeping requirements and the monitoring of occupational exposure to regulated substances.

Other Matters

Impact of inflation

General inflation was moderate during the last three years in most countries where the Company operates; however, the Company s revenues and capital and operating costs are influenced to a larger extent by specific price changes in the oil and gas and allied industries than by changes in general inflation. Crude oil prices generally reflect the balance between supply and demand, with crude oil prices being particularly sensitive to OPEC production levels and/or attitudes of traders concerning supply and demand in the near future. Prices for oil field goods and services are usually affected by the worldwide prices for crude oil.

Prior to the oil price collapse in late 2014 and 2015, the cost for oil field goods and services had generally risen in the preceding years. As noted elsewhere, oil prices have been extremely volatile over the last several years, as oil prices were quite strong in recent years, before declining dramatically in the fourth quarter of 2014 and throughout 2015 due to an oversupply of crude oil in the global marketplace. With the recent decline in oil prices, the demand for goods and services has been diminished, which is leading to significant downward pressure on the prices of these goods and services. Natural gas prices are also affected by supply and demand, which are often affected by the weather and by the fact that delivery of gas is generally restricted to specific geographic areas. North American natural gas prices have been weak due to an oversupply of natural gas in this market. The recent severe pullback in crude oil prices has led many oil companies, including Murphy, to seek price concessions from suppliers of oil field goods and services. Due to the recent severe decline in oil prices coupled with the overall volatility of oil and natural gas prices, it is not possible to predict the Company s future cost of oil field goods and services.

Contractual obligations and guarantees

The Company is obligated to make future cash payments under borrowing arrangements, operating leases, purchase obligations primarily associated with existing capital expenditure commitments, and other long-term liabilities. In addition, the Company expects to extend certain operating leases beyond the minimum contractual period. Total payments due after 2015 under such contractual obligations and arrangements are shown below.

		Amount of Obligations			
(Millions of dollars)	**Total**	**2016**	**2017-2018**	**2019-2020**	**After 2020**
Debt including current maturities	**$ 3,059.5**	18.9	1,172.3	29.2	1,839.1
Operating and other leases	**375.9**	83.3	123.2	92.3	77.1
Capital expenditures, drilling rigs and other	**915.0**	735.0	173.9	3.6	2.5
Other long-term liabilities, including debt interest	**2,278.0**	150.5	237.1	229.5	1,660.9
Total	**$ 6,628.4**	987.7	1,706.5	354.6	3,579.6

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The Company has entered into agreements to lease production facilities for various producing oil fields. In addition, the Company has other arrangements that call for future payments as described in the following section. The Company s share of the contractual obligations under these leases and other arrangements has been included in the table above.

In 2013, the Company entered into a 25-year lease for a semi-floating production system at the Kakap field offshore Sabah, Malaysia. The Company has included the required lease obligations for this production system in the contractual obligation table above.

In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide letters of credit that may be drawn upon if the Company fails to perform under those contracts. Total outstanding letters of credit were $81.6 million as of December 31, 2015, and all of these letters of credit expire in 2016.

Material off-balance sheet arrangements

The Company occasionally utilizes off-balance sheet arrangements for operational or funding purposes. The most significant of these arrangements at year-end 2015 included operating leases of floating, production, storage and offloading vessel (FPSO) for the Kikeh oil field, floating and operating lease for a production facility at the West Patricia field, drilling contracts for onshore and offshore rigs in various countries, and oil and/or natural gas transportation contracts in the U.S. and Western Canada. The leases call for future monthly net lease payments through 2016 at West Patricia and through 2022 at Kikeh. The U.S. and Western Canada transportation contracts require minimum monthly payments through 2024. Future required minimum annual payments under these arrangements are included in the contractual obligation table above.

Outlook

Average worldwide crude oil prices in July 2016 are similar to the average prices during the second quarter of 2016 with Brent and WTI trading at near parity. Non-OPEC crude oil production continues to slide, but total commercial inventories that remain at elevated levels will be slow to clear. Driven by strong seasonal power demand, North American natural gas prices improved in July 2016 relative to the second quarter of 2016 as the U.S commercial inventory excess to the prior year was trimmed by nearly 60% since the end of the withdrawal season in March. The Company expects its total oil and natural gas production to average 167,500 to 169,500 barrels of oil equivalent per day in the third quarter 2016. The Company currently anticipates total capital expenditures for the full year 2016 to be approximately $620 million, excluding the cost to acquire the Kaybob Duvernay and liquids rich Montney interests in Canada.

The Company will primarily fund its capital program and property acquisitions in 2016 using operating cash flow and proceeds from recent divestitures, but supplements funding where necessary using borrowings under available credit facilities. As of June 30, 2016, there were no funds borrowed under its revolving credit facility. The Company s current 2016 outlook calls for no borrowings under its revolving credit agreement during the second of half of 2016. If oil and/or natural gas prices weaken, actual cash flow generated from operations could be reduced such that unanticipated borrowings might be required during the year to maintain funding of the Company s ongoing development projects. The Company s revolving credit facility matures in June 2017, and the Company currently expects to execute a new agreement prior to expiry of the existing facility. A new credit facility may include different terms compared to the existing facility.

The significant reduction in the sales prices of crude oil has caused the Company to reduce capital expenditures, including development drilling and completion operations in North America. The Company s capital spending program in 2016 will be well below 2015 levels. The reduced level of capital expenditures, if it continues, could lead to lower production levels in future periods. A continuation of low oil and/or gas prices or further deterioration therein, could lead to negative future effects on the Company, which could include reductions in proved reserves, additional impairment charges, the necessity for further cost containment measures, higher debt levels, and a reconsideration of the level of dividends on its Common stock.

As of August 3, 2016 the Company has entered into derivative or forward fixed-price delivery contracts to manage risk associated with certain future oil and natural gas sales prices as follows:

Commodities	Contract or Location	Dates	Average Volumes per Day	Average Prices
U.S. Oil	West Texas Intermediate	July Dec. 2016	25,000 bbls/d	$50.67 per bbl.
U.S. Oil	West Texas Intermediate	Jan - Dec. 2017	7,000 bbls/d	$50.10 per bbl.
Canadian Natural Gas	TCPL NOVA System	July Dec. 2016	99 mmcf/d	C$3.00 per mcf
Canadian Natural Gas	TCPL NOVA System	Jan. 2017 Dec. 2020	59 mmcf/d	C$2.81 per mcf

Prices for the Company s primary products are often quite volatile. The price for crude oil is primarily affected by the levels of supply and demand for energy. Anticipated future variances between the predicted demand for crude oil and the projected available supply can lead to significant movement in the price of crude oil. In January 2016, West Texas Intermediate crude oil traded in a band between about $28.46 and $36.76 per barrel and averaged about $31.78 for the full month. NYMEX natural gas traded in a band of $2.12 to $2.53 per MMBTU, with an average of $2.27 during this same time. Both these oil and natural gas prices are well below the average prices achieved in 2015. The Company continually monitors the prices for its main products and often alters its operations and spending plans based on these prices.

Geographically, the current estimate of E&P capital in 2016 is spread approximately as follows: 38% for the United States, 22% for Malaysia, 19% for Canada and 21% for all other areas. Spending in the U.S. is primarily associated with development programs in the Eagle Ford Shale area of South Texas. In Malaysia, the majority of the spending is for continued development of the Kikeh, Kakap-Gumusut and Siakap North-Petai fields in Block K, oil development projects offshore Sarawak in Blocks SK 309/311 and development of a FLNG project in Block H. Canadian spending is primarily associated with natural gas development operations in Western Canada, plus ongoing operations at East Coast offshore areas. Capital and other expenditures will be routinely reviewed during 2016 and planned capital expenditures may be adjusted to reflect differences between budgeted and actual cash flow during the year. Capital expenditures may also be affected by asset purchases or sales, which often are not anticipated at the time a budget is prepared.

The Company currently expects production in 2016 to average between 173,000 and 177,000 barrels of oil equivalent per day. This level of production is less than 2015 due primarily to a significantly lower capital spending program in 2016. A key assumption in projecting the level of 2016 Company production is the anticipated well decline rate following a period of reduced drilling activity in the Eagle Ford Shale area of South Texas where a major drilling and completion operation has been scaled back due to weak oil prices. Other key factors in meeting 2016 production targets is the rate of decline of natural gas wells at the Tupper area in Western Canada, continued reliability of production at significant operations such as Kikeh, Syncrude, Hibernia and Terra Nova, and the continued customer demand for natural gas from the Company s offshore Malaysia fields.

At year-end 2015, the Company had two deepwater drilling rigs under contract in the Gulf of Mexico that were scheduled to expire in February and November 2016. In the face of low commodity prices, a significant reduction in the Company s overall 2016 capital spending program and lack of interest by working interest partners and others to participate in drilling opportunities in 2016, the Company idled and stacked both rigs during the fourth quarter of

2015. The contract originally scheduled to expire in November 2016 was terminated by the Company. The remaining day rate commitments payable in the first quarter of 2016 under both contracts total approximately $271 million.

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In the falling commodity price environment during 2015, the Company gained price concessions from many of its vendors that supply oil field goods and services. Certain costs are expected to retreat further in 2016 at the current level of oil and gas prices. It is unclear how successful the Company will be with achieving additional meaningful reductions in the cost of oil field goods and services.

In April 2016, a Canadian subsidiary of the Company completed its transaction to divest natural gas processing and sales pipeline assets that support Murphy s Montney natural gas fields in the Tupper area of northeastern British Columbia. Total cash consideration received by Murphy upon closing of the transaction was $414.1 million. A gain on sale of approximately $187 million is being deferred and recognized over the next 20 years in the Canadian operating segment. The Company amortized $1.8 million of the deferred gain in the second quarter of 2016. The remaining deferred gain is included as a component of deferred credits and other liabilities on the Company s Consolidated Balance Sheet.

In a separate transaction, the same subsidiary signed a definitive agreement to acquire a 70 percent operated working interest (WI) of Athabasca Oil Corporation s (Athabasca) production, acreage, infrastructure and facilities in the Kaybob Duvernay lands, and a 30 percent non-operated WI of Athabasca s production, acreage, infrastructure and facilities in the liquids rich Montney lands in Alberta, the majority of which is unproven. Under the terms of the joint venture the total consideration amounts to approximately $375 million, of which Murphy will pay approximately $206.7 million in cash at closing and the remaining $168 million in the form of a carry for a period of up to five years. This transaction closed in May 2016.

As of December 31, 2015, Murphy s long-term debt was rated BBB with a negative outlook by Standard and Poor s (S&P), BBB- with a negative outlook by Fitch Ratings (Fitch), and Baa3 with a negative outlook by Moody s Investor Services (Moody s). In February 2016, S&P, Fitch, and Moody s each downgraded the Company s credit rating on its outstanding notes. The Company s long-term debt ratings are currently BBB- with stable outlook by S&P, BB+ with stable outlook by Fitch, and B1 with negative outlook by Moody s. Fitch s and Moody s actions reduced the Company s credit rating to below investment grade status. These downgrades could adversely affect our cost of capital and our ability to raise debt in public markets in future periods. Based on the downgrade by Moody s, the coupon rates on $1.5 billion of the Company s outstanding notes were increased by 1.00% effective June 1, 2016.

Accounting changes and recent accounting pronouncements

Presentation of Debt Issuance Costs. In April 2015, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) that simplifies the presentation of debt issuance costs. The ASU requires that the cost of issuing debt be presented on the balance sheet as a direct reduction from the associated debt liability. These costs have historically been recorded as an asset, rather than a direct reduction of debt. This ASU does not affect the results of operations, as costs of debt issuance will continue to be amortized to interest expense. The Company is required to adopt the ASU effective in the first quarter of 2016, but early adoption is permitted. The Company elected to adopt this ASU early, effective with the first quarter of 2015. This change in accounting principle is preferable due to allowing debt issuance costs and debt issuance discounts to be presented similarly in the Balance Sheet as reductions to recorded debt balances. A retrospective change to the December 31, 2014 Balance Sheet as previously presented is required due to the adoption. The retrospective adjustment to the December 31, 2014 Balance Sheet is shown below:

(Thousands of dollars)	As Previously Reported December 31, 2014	Adjustment Effect	December 31, 2014 As Adjusted
Deferred charges and other assets	$ 81,151	(18,569)	62,582
Long-term debt	(2,536,238)	18,569	(2,517,669)

Balance Sheet Classification of Deferred Taxes. In November 2015, the FASB issued an ASU that requires entities with a classified balance sheet to present all deferred tax assets and liabilities as noncurrent. The current

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requirement that deferred tax assets and liabilities of a tax-paying component of an entity be offset and presented as a single amount is not affected by the amendment. The amendments are effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early adoption is permitted for all entities as of the beginning of an interim or annual reporting period. The amendments may be applied either prospectively to all deferred tax assets and liabilities or retrospectively to all periods presented. The Company will adopt this guidance in 2016 and does not expect the impact of adopting this guidance to be material to the Company s financial statements and related disclosures.

Revenue from Contracts with Customers. In May 2014, the FASB issued a comprehensive new revenue recognition standard for contracts with customers that will supersede most current revenue recognition guidance, including industry-specific guidance. The core principle of this standard is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this core principle, the standard provides a five-step analysis of transactions to determine when and how revenue is recognized. In August 2015, the FASB issued an accounting standards update that formally delayed the effective date of this revenue recognition standard. The new standard is now effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. Early adoption is now permitted for fiscal years, and interim periods within those years, beginning after December 15, 2016. The standard permits the use of either the retrospective or cumulative effect transition method. This guidance will be applicable to the Company beginning on January 1, 2018. The Company has not yet selected a transition method and is currently evaluating the standard and the impact on its consolidated financial statements and footnote disclosures.

Significant accounting policies In preparing the Company s consolidated financial statements in accordance with U.S. GAAP, management must make a number of estimates and assumptions related to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Application of certain of the Company s accounting policies requires significant estimates. The most significant of these accounting policies and estimates are described below.

Oil and gas proved reserves Oil and gas proved reserves are defined by the SEC as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether a deterministic method or probabilistic method is used for the estimation. Proved developed reserves of oil and gas can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well, or through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Although the Company s engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. SEC rules require the Company to use an unweighted average of the oil and gas prices in effect at the beginning of each month of the year for determining quantities of proved reserves. These historical prices often do not approximate the average price that the Company expects to receive for its oil and natural gas production in the future. The Company often uses significantly different oil and natural gas price and reserve assumptions when making its own internal economic property evaluations. Estimated reserves are subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserves quantities.

Reserves revisions inherently lead to adjustments of the Company s depreciation rates and the timing of settlement of asset retirement obligations. Downward reserves revisions can also lead to significant impairment expense. The Company cannot predict the type of oil and gas reserves revisions that will be required in future periods. The Company s proved reserves of crude oil, natural gas liquids and natural gas are presented elsewhere in this prospectus supplement. Murphy s estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data, and commercially available technologies, to establish reasonable certainty of economic producibility. As defined by the SEC, reasonable certainty of proved reserves describes a high-degree of confidence that the quantities will be recovered. In estimating proved reserves, Murphy uses familiar industry-accepted methods for subsurface evaluations, including performance, volumetric, and analog based studies. Where appropriate, Murphy includes reliable geologic and engineering technology to estimate proved reserves. Reliable geologic and engineering technology is a method or combination of methods that are field-tested and have demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. This integrated approach increases the quality of and confidence in Murphy s proved reserves estimates, and was utilized in certain undrilled acreage at distances greater than the directly offsetting development spacing areas, and in certain reservoirs developed with the application of improved recovery techniques. Murphy utilized a combination of 3D seismic interpretation, core analysis, wellbore log measurements, well test data, historic production and pressure data, and commercially available seismic processing and numerical reservoir simulation programs. Reservoir parameters from analogous reservoirs were used to strengthen the reserves estimates when available.

See further discussion of proved reserves and changes in proved reserves during the three years ended December 31, 2015 in the Company s Annual Report on Form 10-K for the year ended December 31, 2015.

Successful efforts accounting The Company utilizes the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells are expensed and can have a significant effect on operating results. Successful exploration drilling costs and all development capital expenditures are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by the Company s engineers. In some cases, a determination of whether a drilled well has found proved reserves cannot be made immediately. This is generally due to the need for a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a capital expenditure is, in turn, usually dependent on whether additional exploratory wells find a sufficient quantity of additional reserves. Under current accounting rules, the Company holds well costs in Property, Plant and Equipment in the Consolidated Balance Sheet when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.
Based on the time required to complete further exploration and appraisal drilling in areas where hydrocarbons have been found but proved reserves have not been booked, dry hole expense may be recorded one or more years after the original drilling costs are incurred. In 2015, the costs associated with one well in the Gulf of Mexico, which was drilled in 2009, was expensed due to it being unlikely to be

developed due to distressed commodity prices. In 2014, the costs associated with four wells offshore Block PM 311 in Malaysia, which were drilled in 2004 and 2005, were written off due to denial of the Company s request to the Malaysian government for an extension to the gas holding period. Additionally, the cost of one well in the Gulf of Mexico, which was drilled in 2008, was written off because low-expected futures prices for natural gas at year-end 2014 rendered development opportunities for the field to be uneconomic. In 2013, two wells offshore Sarawak drilled in 2005 and 2006 were expensed when the Company decided not to move forward with development plans for this area.

Impairment of long-lived assets The Company continually monitors its long-lived assets recorded in Property, Plant and Equipment (PPE) in the Consolidated Balance Sheet to make sure that they are fairly presented. The Company must evaluate its PPE for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable from future cash flows. Goodwill is evaluated for impairment at least annually. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the amount of oil and natural gas that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, future capital and abandonment costs, and future inflation levels. The need to test a long-lived asset for impairment can be based on several factors, including but not limited to a significant reduction in sales prices for oil and/or natural gas, unfavorable revisions of oil or natural gas reserves, or other changes to contracts, environmental regulations or tax laws. All of these same factors must be considered when evaluating a property s carrying value for possible impairment.

In making its impairment assessments involving exploration and production property and equipment, the Company must make a number of projections involving future oil and natural gas sales prices, future production volumes, and future capital and operating costs. Due to the volatility of world oil and gas markets, the actual sales prices for oil and natural gas have often been quite different from the Company s projections. Estimates of future oil and gas production and sales volumes are based on a combination of proved and risked probable and possible reserves. Although the estimation of reserves and future production is uncertain, the Company believes that its estimates are reasonable; however, there have been cases where actual production volumes were higher or lower than projected and the timing was different than the original projection. The Company adjusts reserves and production estimates as new information becomes available. The Company generally projects future costs by using historical costs adjusted for both assumed long-term inflation rates and known or expected changes in future operations. Although the projected future costs are considered to be reasonable, at times, costs have been higher or lower than originally estimated. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events, which include projections of future sales prices, future capital expenditures and future operating expenses. Future marketing or operating decisions, such as closing or selling certain assets, and future regulatory or tax changes could also impact the Company s conclusion about potential asset impairment.

The Company recorded impairment expense of $2,493.2 million in 2015 to reduce the carrying value of producing heavy oil properties in Western Canada, producing offshore properties in Malaysia, and producing and non-producing properties in the Gulf of Mexico to their estimated fair value due to significant declines in future oil and gas prices since the end of 2014. The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges, costs, and a discount rate believed to be consistent with those used by principal market participants in the applicable region. The Company recorded impairment expense of $14.3 million in 2014 for one producing gas field in the Gulf of Mexico due to low year-end natural gas futures prices that would not permit full recovery of the investment in the field. Additionally, in 2014 the Company recorded an impairment charge of $37.0 million to write-off the remaining goodwill originally recorded with a business acquired in Western Canada in 2000. Low oil and gas prices at year-end 2014 led to the conclusion that this goodwill was no longer recoverable. The Company recorded writedowns of $269.2 million in 2014 and $73.0 million in 2013 for discontinued U.K. refining and marketing operations based on a fair value assessment of these assets being abandoned and/or held for sale at year-ends 2014 and 2013. Murphy recorded impairment expense of $21.6 million in 2013 related to the sale of Kainai properties in Western Canada at less than carrying value.

Based on an evaluation of expected future cash flows from properties at year-end 2015, the Company did not have any other significant properties with carrying values that were impaired at that date. The expected future sales prices for crude oil and natural gas used in the evaluation were based on quoted future prices for the respective production periods. These quoted prices are based on market expectations for future hydrocarbon prices, which can often be significantly higher or lower in future periods compared to current spot prices. If quoted prices for future years had been weaker, the lower level of projected cash flows for properties could have led to additional impairment charges being recorded for certain properties in 2015. In addition, one or a combination of other factors such as lower future oil and/or natural gas prices, lower future production volumes, higher future costs, or the actions of government authorities could lead to impairment expenses in future periods. Based on these unknown future factors as described herein, the Company cannot predict the amount or timing of impairment expenses that may be recorded in the future.

Income taxes The Company is subject to income and other similar taxes in all areas in which it operates. When recording income tax expense, certain estimates are required because: (a) income tax returns are generally filed months after the close of its annual accounting period; (b) tax returns are subject to audit by taxing authorities and audits can often take years to complete and settle; and (c) future events often impact the timing of when income tax expenses and benefits are recognized by the Company. The Company has deferred tax assets mostly relating to basis differences for property, equipment and inventories, and liabilities for dismantlement and retirement benefit plan obligations. The Company routinely evaluates all deferred tax assets to determine the likelihood of their realization. A valuation allowance has been recognized for deferred tax assets related to basis differences for Blocks PM 311/312 and SK 314A in Malaysia, for exploration licenses in certain areas, the largest of which are Australia, Indonesia and Brunei, and for certain basis differences in the U.K. due to management s belief that these assets cannot be deemed to be realizable with any degree of confidence at this time.

In 2015, Murphy recognized $188.5 million in noncash tax expense primarily associated with using a U.S. deferred tax asset that would otherwise have carried forward to future years with a dividend from a foreign subsidiary. In 2014, the Company recognized U.S. income tax benefits of $95.9 million related to tax deductions associated with investments in upstream operations in Cameroon, Kurdistan and certain permits in Australia where the Company is exiting operations, as well as a Malaysian tax benefit of $65.4 million related to recognition of the expected future realization of tax deductions for prior-year Block H exploration expenses following sanction of the development plan for this field during 2014. In 2013, the Company recognized U.S. income tax benefits of $133.5 million related to tax deductions associated with investments in upstream operations in Republic of the Congo and Kurdistan, where the Company is exiting operations.

Accounting for retirement and postretirement benefit plans Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering most full-time employees. Effective with the spin-off of the Company s former U.S. retail marketing operation (MUSA) on August 30, 2013, significant modifications were made to the U.S. defined benefit pension plan. Certain employees benefits under the U.S. plan were frozen at that time. No further benefit service will accrue for the affected employees, however, the plan will recognize future compensation increases after the spin-off. In addition, all previously unvested benefits became fully vested at the spin-off date. For those affected active employees of the Company, additional U.S. retirement plan benefits will accrue in future periods under a cash balance formula. Upon the spin-off of MUSA, the Company retained all vested pension defined benefit and other postretirement benefit obligations associated with current and former employees of this business. No additional benefit will accrue for employees of MUSA under the Company s retirement plan after the separation date.

The Company also sponsors health care and life insurance benefit plans covering most retired U.S. employees. The expense associated with these plans is determined by management based on a number of assumptions and with consultation assistance from qualified third-party actuaries. The most important of these assumptions for the retirement plans involve the discount rate used to measure future plan obligations and the expected long-term rate of return on plan assets. For the retiree medical and insurance plans, the most important assumptions are the discount rate for future plan obligations and the health care cost trend rate. Discount rates are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Anticipated health care cost trend rates are determined based on prior experience of the Company and an assessment of near-term and long-term trends for medical and drug costs.

Upon disposal of Murphy s former U.K. downstream assets, the Company retained all vested defined benefit pension obligations associated with former employees of this business. No additional benefits will accrue to these former U.K. employees under the Company s retirement plan after the date of separation from Murphy.

Based on bond yields at December 31, 2015, the Company has used a weighted average discount rate of 4.55% at year-end 2015 for the primary U.S. plans. This weighted average discount rate is 0.43% higher than a year earlier, which decreased the Company s recorded liabilities for retirement plans compared to a year ago. Although the Company presently assumes a return on plan assets of 6.50% for the primary U.S. plan, it periodically reconsiders the appropriateness of this and other key assumptions. The smoothing effect of current accounting regulations tends to buffer the current year s retirement plan expenses from wide swings in liabilities and asset valuations. The Company s retirement and postretirement plan expenses in 2016 are expected be higher than 2015 due to larger costs associated with previously unrecognized actuarial losses at year-end 2015. However, cash contributions are anticipated to be lower in 2016 particularly associated with its domestic retirement plan. In 2015, the Company paid $31.4 million into various retirement plans and $3.8 million into postretirement plans. In 2016, the Company is expecting to fund payments of approximately $8.5 million into various retirement plans and $5.4 million for postretirement plans.

The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed return, or the health care cost trend rate increase is higher than expected. Although Congress passed the Moving Ahead for Progress in the 21st Century Act, which permits certain companies to reduce retirement plan contributions in the near term, this Act does not reduce the Company s overall funding requirements in the long-

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term. As described above, the Company s retirement and postretirement expenses are sensitive to certain assumptions, primarily related to discount rates and assumed return on plan assets. A 0.5% decline in the discount rate would increase 2016 annual retirement and postretirement expenses by $2.9 million and $0.6 million, respectively, and a 0.5% decline in the assumed rate of return on plan assets would increase 2016 retirement expense by $2.5 million.

Legal, environmental and other contingent matters A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and other contingent matters. In addition, the Company often must estimate the amount of such losses. In many cases, management s judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. The Company s management closely monitors known and potential legal, environmental and other contingent matters, and makes its best estimate of the amount of losses and when they should be recorded based on information available to the Company.

Leases In February 2016, The Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) to increase transparency and comparability among companies by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous generally accepted accounting principles (GAAP) and this ASU is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. The new standard is effective for financial statements issued for annual periods beginning after December 15, 2018 and interim periods within those annual periods. Early adoption is permitted for all entities. The Company anticipates adopting this guidance in 2019 and is currently evaluating the standard and its impact on its consolidated financial statements and footnote disclosures.

Compensation Stock Compensation In March 2016, the FASB issued an ASU intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification within the statement of cash flows. The amendments in this ASU are effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early adoption is permitted for any entity in any interim period or annual period. The Company will adopt this guidance in 2017 and is currently evaluating the impact on its consolidated financial statements and footnote disclosures.

Revenue from Contracts with Customers In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), a comprehensive new revenue recognition standard for contracts with customers that will supersede most current revenue recognition requirements and industry-specific guidance. The codification was amended through additional ASUs and, as amended, requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company is required to adopt the new standard in the first quarter of 2018 using either the retrospective or cumulative effect transition method. The Company has not yet selected a transition method and is currently evaluating the standard and the impact on its consolidated financial statements and footnote disclosures.

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Business and properties

Summary

The Company was originally incorporated in Louisiana in 1950 as Murphy Corporation. It was reincorporated in Delaware in 1964, at which time it adopted the name Murphy Oil Corporation, and was reorganized in 1983 to operate primarily as a holding company of its various businesses. For reporting purposes, Murphy s exploration and production activities are subdivided into four geographic segments, including the United States, Canada, Malaysia and all other countries. Additionally, Corporate activities include interest income, interest expense, foreign exchange effects and administrative costs not allocated to the segments. The Company s corporate headquarters are located in El Dorado, Arkansas.

The Company has transitioned from an integrated oil company to an enterprise entirely focused on oil and gas exploration and production activities. This transition was finalized through the sale of our United Kingdom retail marketing assets during 2014, followed by the sale of our remaining downstream assets in the U.K. in the second quarter of 2015.

At December 31, 2015, Murphy had 1,258 employees.

Exploration and Production

The Company s exploration and production business explores for and produces crude oil, natural gas and natural gas liquids worldwide. The Company s exploration and production management team directs the Company s worldwide exploration and production activities. This business maintains upstream operating offices in other locations around the world, with the most significant of these including Houston, Texas, Calgary, Alberta and Kuala Lumpur, Malaysia.

During 2015, Murphy s principal exploration and production activities were conducted in the United States by wholly owned Murphy Exploration & Production Company USA (Murphy Expro USA), in Malaysia, Australia, Brunei, Vietnam, and Namibia by wholly owned Murphy Exploration & Production Company International (Murphy Expro International) and its subsidiaries, and in Western Canada and offshore Eastern Canada by wholly- owned Murphy Oil Company Ltd. (MOCL) and its subsidiaries. Murphy s hydrocarbon production in 2015 was in the United States, Canada and Malaysia. MOCL owns a 5% undivided interest in Syncrude Canada Ltd. in northern Alberta. In December 2014 the Company sold 20% of its interests in Malaysia; a further sale of an additional 10% of its interests in Malaysia was completed in January 2015. Unless otherwise indicated, all references to the Company s oil, natural gas liquids and natural gas production volumes and proved crude oil, natural gas liquids and natural gas reserves are net to the Company s working interest excluding applicable royalties. Also, unless otherwise indicated, references to oil throughout this prospectus supplement could include crude oil, condensate and natural gas liquids where applicable volumes includes a combination of these products.

Murphy s worldwide crude oil, condensate and natural gas liquids production in 2015 averaged 136,634 barrels per day. As described above, the Company sold 30% of its working interest in Malaysia in late 2014 and early 2015. While total liquids production decreased 10% in 2015 compared to 2014, production for the twelve month period ended December 31, 2015 was slightly above the 2014 period as adjusted for the sale in Malaysia. The increase in 2015 when adjusted for the sale was primarily due to higher crude oil and natural gas liquids production in the Eagle Ford Shale area of South Texas. The Company s worldwide sales volume of natural gas averaged 428 million cubic feet (MMCF) per day in 2015. While the Company s worldwide sales volume of natural gas in 2015 was down 4% from 2014 levels production for the twelve month period ended December 31, 2015 increased 11% compared to the 2014 period as adjusted for the Malaysia sale. The increase in natural gas sales volume in 2015 when adjusted for the sale was primarily attributable to higher gas production volumes in the Eagle Ford Shale area of South Texas and Tupper area in Western Canada. Growth in oil and gas production volumes occurred due to further development drilling in the Eagle Ford Shale and Tupper area. Total worldwide

2015 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 207,903 barrels per day, a decrease of 8% compared to 2014, but when adjusted for the sale in Malaysia increased 4% compared to 2014. If the combined sale of 30% interest in Malaysia had occurred on January 1, 2014, total pro forma daily oil and natural gas production volumes would have been approximately 135,100 barrels and 386 MMCF, respectively, in 2014. The 30% sale in Malaysia in late 2014 and early 2015 represented 2014 production of approximately 26,600 barrels of oil equivalent per day (boepd); excluding these volumes, pro forma 2014 production would have been approximately 199,400 boepd.

Total production in 2016 is currently expected to average between 173,000 and 177,000 boepd. Through June 30, 2016, total production in 2016 averaged 182,604 boepd. The projected production decrease in 2016 is primarily due to lower anticipated overall capital spending of more than 70% during the year, excluding the acquisition cost for the Kaybob Duvernay and liquids rich Montney.

United States

In the United States, Murphy primarily has production of crude oil, natural gas liquids and natural gas from fields in the Eagle Ford Shale area of South Texas and in the deepwater Gulf of Mexico. The Company produced 70,675 barrels of crude oil and gas liquids per day and approximately 87 MMCF of natural gas per day in the U.S. in 2015. These amounts represented 52% of the Company s total worldwide oil and 20% of worldwide natural gas production volumes. The Company holds rights to approximately 157 thousand gross acres in South Texas in the Eagle Ford Shale unconventional oil and gas play. Total 2015 oil and natural gas production in the Eagle Ford area was 54,883 barrels per day and approximately 38 MMCF per day, respectively. On a barrel of oil equivalent basis, Eagle Ford production accounted for 72% of our total U.S. production volumes in 2015. Due to scale back of drilling and infrastructure development activities related to weak oil prices, production in the Eagle Ford Shale is forecast to decline and average approximately 41,200 barrels of oil and gas liquids per day and 30 MMCF of natural gas per day in 2016. At December 31, 2015, the Company s proved reserves in the Eagle Ford Shale area totaled 207.9 million barrels of crude oil, 32.1 million barrels of natural gas liquids, and 166 billion cubic feet of natural gas.

During 2015, approximately 28% of total U.S. hydrocarbon production was produced at fields in the Gulf of Mexico. Approximately 84% of Gulf of Mexico production in 2015 was derived from four fields, including Dalmatian, Medusa, Front Runner and Thunder Hawk. The Company holds a 70% interest in Dalmatian in DeSoto Canyon Blocks 4, 48 and 134, 60% interest in Medusa in Mississippi Canyon Blocks 538/582, and 62.5% working interests in the Front Runner field in Green Canyon Blocks 338/339 and the Thunder Hawk field in Mississippi Canyon Block 734. During 2014, the Company acquired a 29.1% non-operated interest in the Kodiak field in Mississippi Canyon Blocks 727/771. Total daily production in the Gulf of Mexico in 2015 was 15,792 barrels of oil and approximately 49 MMCF of natural gas. Production in the Gulf of Mexico in 2016 is expected to total approximately 14,000 barrels of oil and gas liquids per day and 23 MMCF of natural gas per day. At December 31, 2015, Murphy had total proved reserves for Gulf of Mexico fields of 34.2 million barrels of oil and gas liquids and 66 billion cubic feet of natural gas. Total U.S. proved reserves at December 31, 2015 were 238.9 million barrels of crude oil, 35.4 million barrels of natural gas liquids, and 232 billion cubic feet of natural gas.

Canada

In Canada, the Company holds one wholly-owned heavy oil area and one wholly-owned natural gas area in the Western Canadian Sedimentary Basin (WCSB). In addition, the Company owns interests in three non-operated assets the Hibernia and Terra Nova fields offshore Newfoundland in the Jeanne d Arc Basin and Syncrude Canada Ltd. in northern Alberta. Daily production in 2015 in the WCSB averaged 5,456 barrels of mostly heavy oil and approximately 197 MMCF of natural gas. The Company has 101 thousand net acres of Montney mineral rights, which includes the Tupper natural gas producing area located in northeast British Columbia. The Company has 267 thousand net acres of mineral rights in the Seal field located in the Peace River oil sands area

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of northwest Alberta. Oil and natural gas daily production for 2016 in Western Canada, excluding Syncrude, is expected to average 3,600 barrels and approximately 212 MMCF, respectively. The expected decrease in oil production in 2016 arises from well declines and selective economic related well shut-ins in the Seal area due to lower heavy oil prices. The expected increase in natural gas volumes in 2016 is primarily the result of new wells brought on line in the Tupper area and improved performance. Total WCSB proved liquids and natural gas reserves at December 31, 2015, excluding Syncrude, were approximately 4.6 million barrels and 894 billion cubic feet, respectively.

Murphy has a 6.5% working interest in Hibernia, while at Terra Nova the Company s working interest is 10.475%. Oil production in 2015 was about 4,400 barrels of oil per day at Hibernia and 3,000 barrels per day at Terra Nova. Hibernia production declined in 2015 due to maturity of existing wells, while Terra Nova production was slightly higher in 2015 due to higher uptime. Oil production for 2016 at Hibernia and Terra Nova is anticipated to be approximately 5,200 barrels per day and 2,700 barrels per day, respectively. Total proved oil reserves at December 31, 2015 at Hibernia and Terra Nova were approximately 16.3 million barrels and 7.4 million barrels, respectively.

As of December 31, 2015, Murphy owned a 5% non-operated working interest in Syncrude Canada Ltd. (Syncrude), a joint venture located about 25 miles north of Fort McMurray, Alberta. Syncrude utilizes its assets, which include three coking units, to extract bitumen from oil sand deposits and to upgrade this bitumen into a high-value synthetic crude oil. Production in 2015 was about 11,700 net barrels of synthetic crude oil per day. Total proved synthetic oil reserves for Syncrude at year-end 2015 were 114.8 million barrels. Murphy closed the sale of its 5% interest in Syncrude to Suncor Energy Inc. in June 2016 for a purchase price of $739.1 million.

Malaysia

In Malaysia, the Company has majority interests in eight separate production sharing contracts (PSCs). The Company serves as the operator of all these areas other than the unitized Kakap-Gumusut field. The production sharing contracts cover approximately 3.68 million gross acres. In December 2014 and January 2015, the Company sold 30% of its interest in most of its Malaysian oil and gas assets.

Murphy has a 59.5% interest in oil and natural gas discoveries in two shallow-water blocks, SK 309 and SK 311, offshore Sarawak. Approximately 15,900 barrels of oil and gas liquids per day were produced in 2015 at Blocks SK 309/311. Oil and gas liquids production in 2016 at fields in Blocks SK 309/311 is anticipated to total about 13,500 barrels of oil per day, with the reduction from 2015 primarily related to natural field decline. The Company has a gas sales contract for the Sarawak area with PETRONAS, the Malaysian state-owned oil company, and has an ongoing multi-phase development plan for several natural gas discoveries on these blocks. The gas sales contract allows for gross sales volumes of 250 MMCF per day through September 2021, but allows the Company to deliver higher sales volumes as requested. Total net natural gas sales volume offshore Sarawak was about 122 MMCF per day during 2015 (gross 272 MMCF per day). Sarawak net natural gas sales volumes are anticipated to be approximately 114 MMCF per day in 2016. Total proved reserves of liquids and natural gas at December 31, 2015 for Blocks SK 309/311 were 13.3 million barrels and approximately 203 billion cubic feet, respectively.

The Company made a major discovery at the Kikeh field in deepwater Block K, offshore Sabah, Malaysia, in 2002 and added another discovery at Kakap in 2004. An additional discovery was made in Block K at Siakap North in 2009. The Company has interests in three Block K discovered fields, which include Kikeh (56%), Kakap (8.6%) and Siakap North (22.4%) (hereafter Siakap). Total gross acreage held by the Company in Block K as of December 31, 2015 was approximately 82,000 acres. Production volumes at Kikeh averaged approximately 14,700 barrels of oil per day during 2015. Oil production at Kikeh is anticipated to average approximately

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10,500 barrels per day in 2016. The reduction in Kikeh oil production in 2016 is primarily attributable to overall field decline. The Kakap field in Block K is operated by another company and was jointly developed with the Gumusut field owned by others. Early production began in late 2012 at Kakap via a temporary tie-back to the Kikeh production facility. The primary Kakap main field production facility was completed and full-field production started up in October 2014.

Kakap oil production in 2015 totaled about 7,000 net barrels of oil per day. In 2016, Kakap production is expected to average near 9,100 barrels of oil per day. The Siakap oil discovery was developed as a unitized area with the Petai field owned by others, and the combined development is operated by Murphy, with a tie-back to the Kikeh field. Production began in 2014 at Siakap, and daily production averaged near 4,000 barrels of oil for 2015 at this field. In 2016, Siakap field production is expected to average 2,600 barrels of oil per day. The Company has a Block K natural gas sales contract with PETRONAS that calls for gross sales volumes of up to 120 MMCF per day. Gas production in Block K will continue until the earlier of lack of available commercial quantities of associated gas reserves or expiry of the Block K production sharing contract. Natural gas production in Block K in 2015 totaled approximately 22 MMCF per day. Daily gas production in 2016 in Block K is expected to average about 12 MMCF per day. Total proved reserves booked in Block K as of year-end 2015 were 61.8 million barrels of crude oil and about 33 billion cubic feet of natural gas.

The Company also has an interest in deepwater Block H offshore Sabah. In early 2007, the Company announced a significant natural gas discovery at the Rotan well in Block H. The Company followed up Rotan with several other nearby discoveries. Following the partial sell down, Murphy s interests in Block H range between 42% and 56%. Total gross acreage held by the Company at year-end 2015 in Block H was 15.99 million acres. In early 2014, PETRONAS and the Company sanctioned a Floating Liquefied Natural Gas (FLNG) project for Block H, and agreed terms for sales of natural gas to be produced with prices tied to an oil index. First production is currently expected at Block H in 2018. At December 31, 2015, total natural gas proved reserves for Block H were approximately 311 billion cubic feet.

The Company has a 42% interest in a gas holding area covering approximately 2,000 gross acres in Block P. This interest can be retained until January 2018.

In May 2013, the Company acquired an interest in shallow-water Malaysia Block SK 314A. The PSC covers a three year exploration period. The Company s working interest in Block SK 314A is 59.5%. This block includes 1.12 million gross acres. The Company has a 70% carry of a 15% partner in this concession through the minimum work program. The first exploration wells were drilled in 2015 for this block.

In February 2015, the Company acquired a 50% interest in offshore Block SK 2C. The Company operates the block, which includes 1.08 million gross acres. The concession carries one well commitment during the one-year exploration period. The first exploration period has been extended for six months. At the expiration of the first exploration period, the Company can opt to extend for two additional years by agreeing to drill another well.

Murphy has a 75% interest in gas holding agreements for Kenarong and Pertang discoveries made in Block PM 311 located offshore peninsular Malaysia. An application for an extension of a gas holding agreement was presented to PETRONAS in 2014, but the application was rejected. Due to the uncertainty of the future production of the gas discovered in Block PM 311, in 2014 the Company wrote off the prior-year well costs of $47.4 million related to Kenarong and Pertang. The Company never included natural gas for Block PM 311 in its proved gas reserves.

Australia

In Australia, the Company holds eight offshore exploration permits and serves as operator of six of them.

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The first permit was acquired in 2007 with a 40% interest in Block AC/P36 in the Browse Basin. Murphy renewed the exploration permit for an additional five years and in that process relinquished 50% of the gross acreage; the license now covers 482 thousand gross acres and expires in 2019. In 2012, Murphy increased its working interest in the remaining acreage to 100% and subsequently farmed out a 50% working interest and operatorship. The existing work commitment for this license includes further geophysical work.

In May 2012, Murphy was awarded permit WA-476-P in the Carnarvon Basin, offshore Western Australia. The Company holds 100% working interest in the permit which covers 177 thousand gross acres. The WA-476-P permit has a primary term work commitment consisting of seismic data purchase and geophysical studies, and all primary term commitments have been completed for this permit. This permit expires in 2018.

The Company also acquired permit WA-481-P in the Perth Basin, offshore Western Australia, in August 2012. Murphy holds a 40% working interest and operatorship of the permit, which covers approximately 4.30 million gross acres. The work commitment calls for 2D and 3D seismic acquisition and processing, geophysical work and three exploration wells. Three wells were drilled on the license in 2015. All three wells were unsuccessful and costs were expensed. This permit expires in 2018.

In November 2012, Murphy acquired a 20% non-operated working interest in permit WA-408-P in the Browse Basin. The permit comprises approximately 417 thousand gross acres and expires in 2016. Two wells were drilled on the license in 2013. The first well found hydrocarbon but was deemed commercially unsuccessful and was written off to expense. The second well was also unsuccessful and costs were expensed in 2013.

The Company was awarded permit EPP43 in the Ceduna Basin, offshore South Australia, in October 2013. The Company operates the concession and holds a 50% working interest in the permit covering approximately 4.08 million gross acres. The exploration permit has commitments for 2D and 3D seismic, to which acquisition was completed in the first half of 2015. This permit expires in 2020.

In April 2014 and June 2014, Murphy was awarded licenses AC/P57 and AC/P58 in the Vulcan Sub Basin, offshore Western Australia. The respective blocks cover approximately 82 thousand and 692 thousand gross acres, respectively. These exploration permits cover six years each and require 3D seismic reprocessing and a gravity survey.

In March 2015, Murphy was awarded AC/P59 license, another acreage position in the Vulcan Sub Basin, offshore Western Australia. The block covers approximately 300 thousand gross acres. The exploration permit covers six years and requires 3D seismic reprocessing, which began in December 2015.

Brunei

In late 2010, the Company entered into two production sharing agreements for properties offshore Brunei. The Company had a 5% working interest in Block CA-1 and a 30% working interest in Block CA-2. In 2015, the Company exercised a preemptive right that increased its working interest in Block CA-1 to 8.051%. The CA-1 and CA-2 blocks cover 1.44 million and 1.49 million gross acres, respectively. Three successful wells were drilled in Block CA-1 in 2012 and three wells were successfully drilled in Block CA-2 in 2013. The partnership group is evaluating development options for these blocks.

Vietnam

In November 2012, the Company signed a PSC with Vietnam National Oil and Gas Group and PetroVietnam Exploration Production Company, whereby it acquired 65% interest and operatorship of Blocks 144 and 145. The blocks cover approximately 6.55 million gross acres and are located in the outer Phu Khanh Basin. The Company acquired 2D seismic for these blocks in 2013.

In June 2013, the Company acquired a 60% working interest and operatorship of Block 11-2/11 under a PSC. The block covers 677 thousand gross acres. The Company acquired 3D seismic and performed other geological and geophysical studies in this block in 2013. This concession carries a three-well commitment.

In June 2014, the Company farmed into Block 13-03. The Company has a 20% working interest in this concession which covers 853 thousand gross acres. Murphy expensed an unsuccessful exploration well drilled in the block in 2014.

In August 2015, the Company signed a farm-in agreement to acquire 35% of Block 15-1/05 that is pending government approval and assignment.

Indonesia

The Company has interests in two exploration licenses in Indonesia and serves as operator of these concessions. In December 2010, Murphy entered into a PSC in the Wokam II block, offshore West Papua, Moluccas and Papua. Murphy has a 100% interest in the block covering 1.22 million gross acres. The three-year work commitment called for seismic acquisition and processing, which the Company completed in 2013. The Company requested relinquishment of this license in 2015 and final government approval is pending.

In November 2011, the Company acquired a 100% interest in a PSC in the Semai IV block, offshore West Papua. The concession includes 873 thousand gross acres, and the agreement called for work commitments of seismic acquisition and processing, which were undertaken in 2014. The Company requested relinquishment of this license in 2015 and final government approval is pending.

In November 2008, Murphy entered into a PSC in the Semai II block, offshore West Papua. The Company has a 28.3% interest in the block which covered about 543 thousand gross acres after a required partial relinquishment of acreage during 2012. 3D seismic was acquired in 2010 and three unsuccessful exploration wells have been drilled in the block. The Company requested relinquishment of this license in 2014 and final government approval is pending.

In May 2008, the Company entered into a production sharing agreement at a 100% interest in the South Barito block in south Kalimantan on the island of Borneo. Following contractually mandated acreage relinquishment in 2012, the block covered approximately 745 thousand gross acres. The contract granted a six-year exploration term with an optional four-year extension. The Company requested relinquishment of this license in 2014 and final government approval is pending.

Equatorial Guinea

In December 2012, Murphy signed a PSC for block W offshore Equatorial Guinea, with a 45% working interest and operatorship. The government ratified the contract in April 2013. The block is located offshore mainland Equatorial Guinea and encompasses 557 thousand gross acres with water depths ranging from 1,200 to 2,000 meters. The initial exploration period of five years is divided into two sub-periods, a first sub-period of three years and a second sub-period of two years. The first sub-period may be extended one year, and the extension carries an obligation to drill one well. Entering into the second sub-period carries an obligation to drill an additional well. In early 2014, Murphy completed acquisition of new 3D seismic over the entire block. The Company withdrew from this block in 2015 and is currently awaiting government approval to assign its interest to the joint venture partner.

Namibia

In March 2014, the Company acquired a 40% working interest and operatorship of Blocks 2613 A/B. The Company acquired the working interest through a farm-out arrangement under the existing petroleum agreement entered into in October 2011. The block encompasses 2,734 thousand gross acres with water depths ranging from 400 to 2,500 meters. The initial exploration period of four years may be extended one year. Entering the first renewal period has the obligation to drill an exploration well. Entering the second renewal period has the obligation to drill an additional well. In 2014, Murphy completed acquisition of new 3D seismic over the block. Using the available seismic data, the Company is evaluating the potential for drilling.

Cameroon

In October 2011, Murphy was granted government approval to acquire a 50% working interest and operatorship of the Ntem concession. The working interest was acquired through a farm-out agreement of the existing production sharing contract. The Ntem block, situated in the Douala Basin offshore Cameroon, encompasses 573 thousand gross acres, with water depths ranging from 300 to 1,900 meters. The concession was in force majeure until January 2014. With force majeure lifted, the Company drilled an unsuccessful exploration well on the Ntem prospect in 2014. The Company declared force majeure again in May 2014. The Company withdrew from this block in 2015.

Suriname

In December 2011, Murphy signed a PSC with Suriname s state oil company, Staatsolie Maatschappij Suriname N.V. (Staatsolie), whereby it acquired a 100% working interest and operatorship of Block 48 offshore Suriname. The block encompasses 794 thousand gross acres with water depths ranging from 1,000 to 3,000 meters. In early 2014, Murphy farmed out a portion of its working interest in Block 48, thereby reducing its interest from 100% to 50% and in early 2015 Murphy relinquished its license in this block.

Republic of the Congo

The Company formerly had interests in Production Sharing Agreements covering two offshore blocks in Republic of the Congo Mer Profonde Sud (MPS) and Mer Profonde Nord (MPN). In 2005, Murphy made an oil discovery at Azurite Marine #1 in the southern block, MPS. Total oil production in 2013 averaged 1,000 barrels per day at Azurite for the Company s 50% interest. The field was shut down and ceased production in the fourth quarter of 2013 and abandonment operations were completed in 2014. Abandonment and other exit charges of $82.5 million were recorded in 2013 associated with the earlier than anticipated shutdown of the Azurite field. The MPN block exploration license expired on December 30, 2012 and MPS block exploration license expired in March 2013. Murphy decommissioned the Azurite field upon completion of abandonment in 2014 and has exited the country.

United Kingdom Discontinued Operations

Murphy produced oil and natural gas in the United Kingdom sector of the North Sea for many years. In 2013, Murphy sold all of its oil and gas properties in the U.K. with an after-tax gain of $216.1 million on the sale. Total 2013 production in the U.K. on a full-year basis amounted to about 600 barrels of oil per day and 1 MMCF of natural gas per day. The Company has accounted for U.K. oil and gas activities as discontinued operations for all periods presented.

Ecuador Discontinued Operations

Murphy sold its 20% working interest in Block 16, Ecuador in March 2009.

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Proved Reserves

Total proved reserves for crude oil, synthetic oil, natural gas liquids and natural gas as of December 31, 2015 are presented in the following table.

	Proved Reserves			
	Crude Oil	Synthetic Oil	Natural Gas Liquids	Natural Gas
		(millions of barrels)		(billions of cubic feet)
Proved Developed Reserves:				
United States	125.9		20.7	148.3
Canada(1)	23.8	114.8	0.3	453.5
Malaysia	62.1		0.6	181.7
Total proved developed reserves(1)	211.8	114.8	21.6	783.5
Proved Undeveloped Reserves:				
United States	113.0		14.7	84.1
Canada	4.1		0.1	456.1
Malaysia	12.5			365.1
Total proved undeveloped reserves	129.6		14.8	905.3
Total proved reserves(1)	341.4	114.8	36.4	1,688.8

(1) Murphy s proved reserves of synthetic oil as of December 31, 2015 were attributable to Murphy s equity interest in Syncrude. Murphy completed the sale of its interest in Syncrude to Suncor Energy Inc. in June 2016, and does not currently own any proved reserves of synthetic crude oil.

Murphy Oil s total proved reserves and proved undeveloped reserves increased during 2015 as presented in the table that follows:

(Millions of oil equivalent barrels)	Total Proved Reserves	Total Proved Undeveloped Reserves
Beginning of year	756.5	279.5
Revisions of previous estimates	16.2	(29.8)
Improved recovery	2.7	
Extension and discoveries	98.6	98.6
Conversion to proved developed reserves		(42.7)
Purchases of properties		
Sales of properties	(24.1)	(10.3)
Production	(75.9)	
End of year	774.0	295.3

During 2015, Murphy added proved reserves of 17.5 million barrels of oil equivalent (MMBOE). The most significant adds to total proved reserves related to drilling and well performance in the Montney gas area of Western Canada that added 20.0 MMBOE, and drilling and well performance in the Eagle Ford Shale that added 78.0 MMBOE. The Company sold an additional 10% of its oil and gas assets in Malaysia during the year which reduced its proved reserves by 24.1 MMBOE. Murphy s total proved undeveloped reserves at December 31, 2015 increased 15.8 MMBOE from a year earlier. The conversion of non-proved reserves to newly reported proved undeveloped reserves reported in the table as extensions and discoveries during 2015 was predominantly attributable to two areas drilling in the Eagle Ford Shale area of South Texas and the Montney area in Western Canada as these areas had active development work ongoing during the year. The majority of proved

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undeveloped reserves reductions associated with revisions of previous estimates were the result of lower oil and gas prices causing these volumes to either become uneconomical or expire due to reallocated capital. The majority of the proved undeveloped reserves migration to the proved developed category occurred in the Eagle Ford Shale, Gulf of Mexico and Montney, attributed to drilling.

The Company sold an additional 10% interest in its Malaysian oil and gas properties in early 2015 which led to a reduction of proved undeveloped reserves of 10.3 MMBOE during the year. The Company spent approximately $800.0 million in 2015 to convert proved undeveloped reserves to prove developed reserves. The Company expects to spend about $400 million in 2016, $400 million in 2017 and $500 million in 2018 to move currently undeveloped proved reserves to the developed category. The anticipated level of spend in 2016 primarily includes drilling in the Eagle Ford Shale and Tupper gas areas. In computing MMBOE, natural gas is converted to equivalent barrels of oil using a ratio of six thousand cubic feet (MCF) to one barrel of oil.

At December 31, 2015, proved reserves are included for several development projects, including oil developments at the Eagle Ford Shale in South Texas and the Kakap, Kikeh and Siakap fields, offshore Sabah, Malaysia, as well as natural gas developments offshore Sarawak and offshore Block H, Malaysia. Total proved undeveloped reserves associated with various development projects at December 31, 2015 were approximately 295 MMBOE, which is 38% of the Company s total proved reserves. Certain development projects have proved undeveloped reserves that will take more than five years to bring to production. The Company operates deepwater fields in the Gulf of Mexico that have three undeveloped locations that exceed this five-year window. Total reserves associated with the three locations amount to less than 1% of the Company s total proved reserves at year-end 2015. The development of certain of these reserves stretches beyond five years due to limited well slots available, thus making it necessary to wait for depletion of other wells prior to initiating further development of these locations. The second project that will take more than five years to develop is offshore Malaysia and makes up approximately 1% of the Company s total proved reserves at year-end 2015. This project is an extension of the Sarawak natural gas project and is expected to be on production in 2018 once current project production volumes decline. Additionally, the Block H development project has undeveloped proved reserves that make up 7% of the Company s total proved reserves at year-end 2015. This operated project will take longer than five years from discovery to completely develop due to construction of floating LNG facilities and the remote location offshore deep waters in Sabah Malaysia. Field start up is expected to occur in 2018, which is less than five years beyond the period that proved undeveloped reserves were first recorded.

Murphy Oil s Reserves Processes and Policies

The Company employs a Manager of Corporate Reserves (Manager) who is independent of the Company s oil and gas management. The Manager reports to the Senior Vice President, Corporate Planning & Services, of Murphy Oil Corporation, who in turn reports directly to the President and Chief Executive Officer of Murphy Oil. The Manager makes presentations to the Board of Directors periodically about the Company s reserves. The Manager reviews and discusses reserves estimates directly with the Company s reservoir engineering staff in order to make every effort to ensure compliance with the rules and regulations of the SEC and industry. The Manager coordinates and oversees reserves audits. These audits are performed annually and target coverage of approximately one-third of Company reserves each year. The audits are performed by the Manager and qualified engineering staff from areas of the Company other than the area being audited. The Manager may also utilize qualified independent reserves consultants to assist with the internal audits or to perform separate audits as considered appropriate.

Each significant exploration and production office maintains one or more Qualified Reserve Estimators (QRE) on staff. The QRE is responsible for estimating and evaluating reserves and other reserves information for his or her assigned area. The QRE may personally make the estimates and evaluations of reserves or may supervise and approve the estimation and evaluation thereof by others. A QRE is professionally qualified to perform these reserves estimates due to having sufficient educational background, professional training and professional experience to enable him or her to exercise prudent professional judgment.

Normally, this requires a minimum of three years practical experience in petroleum engineering or petroleum production geology, with at least one year of such experience being in the estimation and evaluation of reserves, and either a bachelors or advanced degree in petroleum engineering, geology or other discipline of engineering or physical science from a college or university of recognized stature, or the equivalent thereof from an appropriate government authority or professional organization.

Larger offices of the Company also employ a Regional Reserves Coordinator (RRC) who supervises the local QREs. The RRC is usually a senior QRE that has the primary responsibility for coordinating and submitting reserves information to senior management.

The Company s QREs maintain files containing pertinent data regarding each significant reservoir. Each file includes sufficient data to support the calculations or analogies used to develop the values. Examples of data included in the file, as appropriate, include: production histories; pertinent drilling and workover histories; bottom hole pressure data; volumetric, material balance, analogy or other pertinent reserve estimation data; production performance curves; narrative descriptions of the methods and logic used to determine reserves values; maps and logs; and a signed copy of the conclusion of the QRE stating, that in their opinion, the reserves have been calculated, reviewed, documented and reported in compliance with the regulations and guidelines contained in the reserves training manual. The Company s reserves are maintained in an industry recognized reservoir engineering software system, which has adequate access controls to avoid the possibility of improper manipulation of data. When reserves calculations are completed by QREs and appropriately reviewed by RRCs and the Manager, the conclusions are reviewed and discussed with the head of the Company s exploration and production business and other senior management as appropriate. The Company s Controller s department is responsible for preparing and filing reserves schedules within the Form 10-K report.

Murphy provides annual training to all company reserves estimators to ensure SEC requirements associated with reserves estimation and Form 10-K reporting are fulfilled. The training includes materials provided to each participant that outlines the latest guidance from the SEC as well as best practices for many engineering and geologic matters related to reserves estimation.

Qualifications of Manager of Corporate Reserves

The Company believes that it has qualified employees preparing oil and gas reserves estimates. Mr. F. Michael Lasswell serves as Corporate Reserves Manager after joining the Company in 2012. Prior to joining Murphy, Mr. Lasswell was employed as a Regional Coordinator of reserves at a major integrated oil company. He worked in several capacities in the reservoir engineering department with the oil company from 2002 to 2012. Mr. Lasswell earned a Bachelor s of Science degree in Civil Engineering and a Masters of Science degree in Geotechnical Engineering from Brigham Young University. Mr. Lasswell has experience working in the reservoir engineering field in numerous areas of the world, including the North Sea, the U.S. Arctic, the Middle East and Asia Pacific. He serves on the Society of Petroleum Engineers (SPE) Oil and Gas Reserves Committee (OGRC) and is also co-author of a paper on the Recognition of Reserves which was published by the SPE. Mr. Lasswell has also attended numerous industry training courses.

More information regarding Murphy s estimated quantities of proved reserves of crude oil, natural gas liquids and natural gas for the last three years are presented by geographic area on pages F-55 through F-61 of the financial statements included elsewhere and incorporated by reference in this prospectus supplement and the accompanying prospectus. Murphy has not filed and is not required to file any estimates of its total proved oil or gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the U.S. Securities and Exchange Commission. Annually, Murphy reports gross reserves of properties operated in the United States to the U.S. Department of Energy; such reserves are derived from the same data from which estimated proved reserves of such properties are determined.

Crude oil, condensate and natural gas liquids production and sales, and natural gas sales by geographic area with weighted average sales prices for each of the three years ended December 31, 2015 are shown on pages S-37, S-38 and S-41 of this prospectus supplement. In 2015, the Company s production of oil and natural gas represented approximately 0.1% of worldwide totals.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed beginning on page S-43 of this prospectus supplement. For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of oil using a ratio of six MCF of natural gas to one barrel of oil.

Supplemental disclosures relating to oil and gas producing activities are reported on pages F-53 through F-68 of the financial statements included elsewhere and incorporated by reference in this prospectus supplement and the accompanying prospectus.

At December 31, 2015, Murphy held leases, concessions, contracts or permits on developed and undeveloped acreage as shown by geographic area in the following table. Gross acres are those in which all or part of the working interest is owned by Murphy. Net acres are the portions of the gross acres attributable to Murphy s interest.

	Developed		**Undeveloped**		**Total**	
Area (Thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States Onshore	107	98	50	49	157	147
Gulf of Mexico	14	6	918	563	932	569
Total United States	121	104	968	612	1,089	716
Canada Onshore, excluding oil sands	77	77	407	385	484	462
Offshore	101	8	43	2	144	10
Oil sands Syncrude	96	5	160	8	256	13
Total Canada	274	90	610	395	884	485
Malaysia	260	152	3,423	1,752	3,683	1,904
Australia			10,517	4,898	10,517	4,898
Brunei			2,935	563	2,935	563
Vietnam			8,094	4,843	8,094	4,843
Namibia			2,734	1,094	2,734	1,094
Indonesia			3,079	2,690	3,079	2,690
Equatorial Guinea			557	251	557	251
Spain			36	6	36	6
Totals	655	346	32,953	17,104	33,608	17,450

Certain acreage held by the Company will expire in the next three years. Scheduled expirations in 2016 include 918 thousand net acres in Wokam II Block in Indonesia; 745 thousand net acres in South Barito Block in Indonesia; 218 thousand net acres in Semai IV Block in Indonesia; 670 thousand net acres in Block SK 314A in Malaysia; 36

thousand net acres in Block PM 311 in Malaysia; 427 thousand net acres in Blocks 144 and 145 in Vietnam; 81 thousand net acres in Block 11-2/11 in Vietnam; 135 thousand net acres in the United States; and 97 thousand net acres in Western Canada. Scheduled acreage expirations in 2017 include 154 thousand net acres in Semai II Block in Indonesia; 42 thousand net acres in Block WA-408-P in Australia; 51 thousand net acres in the United States; and 41 thousand net acres in Western Canada. Acreage currently scheduled to expire in 2018 include 655 thousand net acres in Semai IV Block in Indonesia; 142 thousand net acres in the United States; 34 thousand net acres in Blocks 13-03 in Vietnam; and 10 thousand net acres in Western Canada.

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As used in the three tables that follow, gross wells are the total wells in which all or part of the working interest is owned by Murphy, and net wells are the total of the Company s fractional working interests in gross wells expressed as the equivalent number of wholly owned wells. An exploratory well is drilled to find and produce crude oil or natural gas in an unproved area and includes delineation wells which target a new reservoir in a field known to be productive or to extend a known reservoir beyond the proved area. A development well is drilled within the proved area of an oil or natural gas reservoir that is known to be productive.

The following table shows the number of oil and gas wells producing or capable of producing at December 31, 2015.

	Oil Wells		**Gas Wells**	
Country	**Gross**	**Net**	**Gross**	**Net**
United States	769	654	19	15
Canada	433	390	219	219
Malaysia	98	51	56	35
Totals	1,300	1,095	294	269

Murphy s net wells drilled in the last three years are shown in the following table.

	United States		**Canada**		**Malaysia**		**Other**		**Totals**	
	Pro-ductive	**Dry**	**Pro-ductive**	**Dry**	**Pro-ductive**	**Dry**	**Pro-ductive**	**Dry**	**Pro-ductive**	**Dry**
2015										
Exploratory		**2.2**			**2.0**	**1.2**		**1.2**	**2.0**	**4.6**
Development	**109.6**		**7.0**		**15.9**				**132.5**	
2014										
Exploratory	1.0	0.8						1.9	1.0	2.7
Development	187.2		48.0	11.0	16.2				251.4	11.0
2013										
Exploratory	15.2	0.4		1.0			0.9	1.4	16.1	2.8
Development	161.2		22.0	19.0	16.3				199.5	19.0

The Canadian dry development wells shown above in 2013 and 2014 are stratigraphic wells used to obtain information about Seal area heavy oil reservoirs. These wells will not be used to produce oil.

Murphy s drilling wells in progress at December 31, 2015 are shown in the following table. The year-end well count includes wells awaiting various completion operations. The U.S. net wells included below are essentially all located in the Eagle Ford Shale area of South Texas.

	Exploratory		**Development**		**Total**	
Country	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States			38	36.0	38	36.0
Canada			2	2.0	2	2.0
Malaysia			1	0.6	1	0.6
Totals			41	38.6	41	38.6

Refining and Marketing Discontinued Operations

The Company completed the separation of its former retail marketing business in the United States on August 30, 2013, through a distribution of 100% of the shares of Murphy USA Inc. (MUSA) to shareholders of Murphy Oil. MUSA is a stand-alone, publicly owned company which is listed on the New York Stock Exchange under the ticker symbol MUSA.

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The Company decommissioned the Milford Haven refinery units and completed the sale of its remaining downstream assets in the U.K. in the second quarter of 2015 for cash proceeds of $5.5 million. The Company has accounted for this U.K. downstream business as discontinued operations for all periods presented.

All of the results of the U.S. and U.K. downstream businesses have been reported as discontinued operations for all periods presented in this prospectus supplement.

Environmental

Murphy s businesses are subject to various international, national, state, provincial and local environmental laws and regulations that govern the manner in which the Company conducts its operations. The Company anticipates that these requirements will continue to become more complex and stringent in the future.

Further information on environmental matters and their impact on Murphy are contained in Management s discussion and analysis of financial condition and results of operations on pages S-28 through S-65 of this prospectus supplement.

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Description of other indebtedness

Revolving Credit Facility

At June 30, 2016, we had a $2.0 billion committed credit facility with a major banking consortium that expires in 2017 (the Existing Revolving Credit Facility). Borrowings under the Existing Revolving Credit Facility bear interest at 1.45% above LIBOR based on the Company s current credit rating as of June 30, 2016. In addition, facility fees of 0.30% are charged on the full $2.0 billion commitment. At June 30, 2016, we had no borrowings under the Existing Revolving Credit Facility. We had outstanding letters of credit of approximately $88 million issued under our Existing Revolving Credit Facility at June 30, 2016, which reduced the available borrowing capacity under the agreement. At June 30, 2016, we also had uncommitted credit lines that had estimated total borrowing capacity of approximately $195 million of which no amounts were outstanding under these uncommitted credit lines.

Concurrently with or prior to the consummation of this offering, we intend to enter into a new revolving credit facility (the New Revolving Credit Facility) in an aggregate principal amount of up to $1.2 billion with a maturity date that will be three years after the date the conditions to availability have been satisfied. Borrowings under the New Revolving Credit Facility will initially bear interest at 4.50% above LIBOR and thereafter be subject to step-downs based on consolidated leverage ratios. In addition, facility fees of 0.50% are charged on the full $1.2 billion commitment. In addition, we intend to amend the Existing Revolving Credit Facility to reduce the commitments of the exiting lenders that have committed to the New Revolving Credit Facility and allow for the incurrence of the New Revolving Credit Facility. Lenders under the Existing Credit Facility that do not become lenders under the New Revolving Credit Facility will remain lenders under our Existing Revolving Credit Facility, with aggregate commitments of $630 million, until its currently scheduled maturity in June 2017.

Following the closing of the New Revolving Credit Facility, our New Revolving Credit Facility will be guaranteed by certain of our material subsidiaries and will contain customary financial maintenance covenants, including requirements to meet a maximum total leverage ratio and a minimum interest coverage ratio and maintain minimum domestic liquidity coverage. Additionally, our New Revolving Credit Facility will contain customary negative covenants, including limitations on additional indebtedness, guarantees and liens. These financial and negative covenants will be subject to customary thresholds and exceptions. In addition, if our total leverage ratio falls below a specified ratio, we will be obligated to provide, subject to certain exceptions, a pledge of substantially all of our tangible and intangible assets, as well as the tangible and intangible assets of the guarantors.

Consummation of this offering is a condition precedent to the effectiveness of the New Revolving Facility.

Existing Notes

On May 4, 1999, we issued $250 million aggregate principal amount of 7.05% Notes due 2029 (the 2029 Notes) under an indenture dated as of May 4, 1999 between us and SunTrust Bank, Nashville, N.A., as trustee and a supplemental indenture thereto dated as of May 4, 1999.

On May 18, 2012, we issued $500 million aggregate principal amount of 4.00% Notes due 2022 (the 2022 Notes) under an indenture dated as of May 18, 2012 between us and U.S. Bank National Association, as trustee, and the first supplemental indenture thereto dated as of May 18, 2012.

On November 30, 2012, we issued $550 million aggregate principal amount of 2.500% Notes due 2017 (the 2017 Notes), $600 million aggregate principal amount of 3.700% Notes due 2022 (the 2022 Notes) and $350 million aggregate principal amount of 5.125% Notes due 2042 (the 2042 Notes and together with the 2029 Notes, the 2022

Notes, the 2017 Notes and the 2022 Notes, the Existing Notes) under the indenture dated as of May 18, 2012 between us and U.S. Bank National Association, as trustee, and the second supplemental indenture thereto dated as of November 30, 2012.

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The indentures for our Existing Notes contain certain restrictions, including a limitation that restricts our ability and the ability of our restricted subsidiaries to incur liens and enter into sale and leaseback transactions. The indentures also restrict our ability to merge or consolidate with any other corporation or sell or convey all or substantially all of its assets.

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Description of the notes

We have summarized selected provisions of the notes below. This summary supplements and replaces, where inconsistent, the description of the general terms and provisions of debt securities under the caption Description of Debt Securities in the accompanying prospectus. As used in the description below, the terms Murphy Oil Corporation, we, our, us, the Company, Murphy Oil and Murphy refer to Murphy Oil Corporation only and not to any of it subsidiaries. Certain terms used in this description are defined under the subheading Certain definitions.

General

The notes will be issued as a separate series of notes under the senior indenture dated as of May 18, 2012 and a supplement to the indenture, to be dated as of , 2016 and hereafter collectively referred to as the indenture, between Murphy Oil and U.S. Bank National Association, as trustee. The notes offered hereby will vote as a separate class from the other series of notes issued under the indenture, except as otherwise provided in the indenture.

The notes will initially be limited to an aggregate principal amount of $500,000,000.

The notes will mature on , 2024 and will bear interest at % per year. Interest on the notes will accrue from , 2016.

We:

- will pay interest on the notes semiannually on and of each year, commencing , 2017;
- will pay interest on the notes to the person in whose name a note is registered at the close of business on the or preceding the interest payment date;
- will compute interest on the notes on the basis of a 360-day year consisting of twelve 30-day months;
- will make payments on the notes at the offices of the trustee; and
- may make payments by wire transfer for notes held in book-entry form or by check for notes held in certificated form mailed to the address of the person entitled to the payment as it appears in the note register.