ConocoPhillips
P.O. Box 100360
Anchorage, Alaska 99510-0360
Phone: (907) 263-3700

**Barry Romberg**
Manager, Alaska Transportation

July 12, 2018

Mr. Jason Walsh
State Pipeline Coordinator
Division of Oil and Gas
State Pipeline Coordinator's Section
3651 Penland Parkway
Anchorage, AK 99508

**Re: Response to Letter No. 18-044-AS Notification of Renewal and Appraisals Due for the Alpine Oil and Alpine Diesel Pipeline Right-of-Way Leases and Alpine Utility Pipeline Right-of-Way Grant (ADLs 415701, 415932, 415857)**

Dear Mr. Walsh

In response to the Division of Oil and Gas, State Pipeline Coordinator's Section (SPCS) Letter No. 18-044-AS, dated February 23, 2018, ConocoPhillips Company, Lessee for the Alpine Pipelines Rights-of-Way Leases (ADLs 415701 and 415932) and Grant (ADL 415857) (collectively the "Leases"), hereby seeks renewal of the Leases for 30 years, the maximum period authorized by law, and on the same terms and conditions as those set forth in the existing leases and amendments thereto.

At the same time, CPC seeks to amend Section 2(c) of the Alpine Utility Grant for a renewal period of 30 years, the maximum period authorized by law, and on the same terms and conditions as those set forth in the existing grant and amendments thereto and provides the instrument to amend Section 2.c. with the Renewal Information Package of information attached.

CPC offers the following to address the requests for information presented in Letter No. 18-044-AS for the purpose of renewing each Lease and Grant

1. Letter of Intent (this document)
2. Lessee Commercial Business Information
3. Statement of Full Compliance with State Law
4. Pipeline and Right-of-Way Information
5. Lease Requirements
6. Management Program/Compliance Systems and Processes
7. Alpine Utility Grant Amendment Instrument

CPC is attaching a confidential version and a public version of the requested information to separate confidential information from non-confidential information as requested by the SPCS in letter 17-372-AS.

Please contact Sandra Pierce at 907-265-6316 or me if you have questions or require additional information.

Sincerely,

Barry Romberg
Manager, Alaska Transportation

Attachments

Confidential Submission:

Attachment 1: Lessee Commercial Business Information
Attachment 2: Statement of Full Compliance with State Law
Attachment 3: Pipeline and Right-of-Way Information
Attachment 4: Lease Requirements
Attachment 5: Management Program/Compliance Systems and Processes
Attachment 6: Alpine Utility Amendment Instrument

Public Submission:

Attachment 1: Lessee Commercial Business Information
Attachment 2: Statement of Full Compliance with State Law
Attachment 3: Pipeline and Right-of-Way Information
Attachment 4: Lease Requirements
Attachment 5: Management Program/Compliance Systems and Processes (*Confidential information redacted*)
Attachment 6: Alpine Utility Amendment Instrument

cc: Electronic Copy Only without Attachments

CPF3 DOT & Ops Pipeline Superintendent
DOT Compliance Specialist
Tom Jantunen
Emily Zanto
Sandra Pierce

# PUBLIC VERSION: ALPINE PIPELINES RENEWAL PACKET

This version is the **PUBLIC VERSION** of the Alpine Pipelines Renewal Packet of information submitted to the State Pipeline Coordinator in response to Letter No. 18-044-AS.

This packet of information **DOES NOT** contain confidential information and is for public consumption.

# ATTACHMENT 1

a. Commercial Business License
b. Certificate of Good Standing/Compliance from the Division of Corporations
c. Annual Financial Statement and Balance Sheets 2015-2017
d. Ownership Interest Diagram

# ATTACHMENT 1

a. **Commercial Business License**
b. Certificate of Good Standing/Compliance from the Division of Corporations
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**Alaska Business License #** **298354**

**Alaska Department of Commerce, Community, and Economic Development**

Division of Corporations, Business and Professional Licensing

P.O. Box 110806, Juneau, Alaska 99811-0806

This is to certify that

# CONOCOPHILLIPS COMPANY

P.O. BOX 100360 (ATO-2008) ANCHORAGE AK 99510

owned by

CONOCOPHILLIPS COMPANY

is licensed by the department to conduct business for the period

December 11, 2017 through December 31, 2019

for the following line of business:

21 - Mining

This license shall not be taken as permission to do business in the state without having complied with the other requirements of the laws of the State or of the United States.

This license must be posted in a conspicuous place at the business location. It is not transferable or assignable.

Mike Navarre

# ATTACHMENT 1

a. Commercial Business License
b. **Certificate of Good Standing/Compliance from the Division of Corporations**
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Alaska Entity #1732F

## State of Alaska
## Department of Commerce, Community, and Economic Development
## Corporations, Business, and Professional Licensing

# Certificate of Compliance

The undersigned, as Commissioner of Commerce, Community, and Economic Development of the State of Alaska, and custodian of corporation records for said state, hereby issues a Certificate of Compliance for:

**CONOCOPHILLIPS COMPANY**
**transacting business in this state under the name of**
**CONOCOPHILLIPS COMPANY**

This entity was formed on February 09, 1953 and is in good standing. This entity has filed all biennial reports and fees due at this time.

No information is available in this office on the financial condition, business activity or practices of this corporation.

IN TESTIMONY WHEREOF, I execute the certificate and affix the Great Seal of the State of Alaska effective **January 11, 2018**.

Mike Navarre
Commissioner

# ATTACHMENT 1

a. Commercial Business License
b. Certificate of Good Standing/Compliance from the Division of Corporations
c. **Annual Financial Statement and Balance Sheets 2015-2017**
d. Ownership Interest Diagram

ConocoPhillips

# 2015 Annual Report

# Contents



On the Cover:
For more than 40 years, the Ekofisk Complex in the Norwegian North Sea has been a source of stable base production.

# Letter to Shareholders

Dear Fellow Shareholders:

Last year in this letter I discussed the unique challenges confronting our industry. A dramatic downturn in oil and natural gas prices was gaining momentum, setting the stage for a tough market in 2015. We approached the year with a plan to maintain capital flexibility, exercise vigilance on costs, drive efficiencies in everything we do, and lower the cost of supply across our asset base. We were prepared to adjust our plans as market conditions changed.

Our goal wasn't just to weather a difficult environment, but to position ConocoPhillips to succeed in an era of low prices and volatility. We believe this is the new energy paradigm—at least for the foreseeable future. In an industry where we can't control prices, it is essential that we focus on factors we can control, while managing short-, medium- and long-term interests.

I'm pleased with the steps we took to adjust to the challenging market conditions in 2015. We quickly cut our capital expenditures by exercising flexibility and high-grading our activities across the business. We also acted quickly to capture deflation and implement sustainable changes to our operating costs. We set an aggressive target early in 2015 to reduce operating costs by $1 billion—a goal we far exceeded. And we took a hard look at our portfolio. We recognized that deepwater exploration and non-core North American natural gas assets weren't going to compete for funding in the future, so we took steps to reduce capital and divest or transition out of some areas of those businesses.

I have no doubt that we took timely and prudent actions on the business factors we could control during 2015. I commend our employees for their efforts and commitment during a volatile year.

**Our 2015 Performance**

Our operational performance in 2015 reflected a strong focus on execution from our workforce. We delivered steady production from legacy assets, achieved seven major project startups and completed turnaround activity across the portfolio. We also continued pilot testing and development drilling in our North American unconventional programs. When it came to what we could control, we delivered.

In contrast, our financial results clearly reflected the key factor we couldn't control—weak oil and natural gas prices. Financial results across the sector were sobering reminders of the challenges low commodity prices pose to profitability. Details on our 2015 financial results can be found on pages 4-5 of this report.

**A summary of 2015 highlights includes:**

- Improved safety performance with a total recordable rate (TRR) of 0.20, our lowest since becoming an independent E&P company in 2012;
- Exceeded our year-over-year production growth target with 5 percent growth from continuing operations, adjusted for Libya, downtime and dispositions;
- Decreased capital spending by 41 percent and reduced operating costs by 14 percent compared with 2014;
- Completed approximately $2 billion of non-core asset dispositions, primarily from North American natural gas and non-producing infrastructure assets; and
- Delivered seven major project startups, including megaprojects at APLNG in Australia and Surmont 2 in Canada.

These achievements came in conjunction with internal efforts to sustainably lower our cost structure and improve efficiency. We're focusing our technology efforts on measures to meaningfully reduce the cost of supply of our captured resource base. Through a company-wide initiative, *Doing Business Better*, we're building a more competitive ConocoPhillips that can outperform through industry cycles. This work required some difficult decisions in 2015, including a 17 percent global workforce reduction and a consolidation in management positions to streamline decision making.

This focus on sustainably lowering our cost structure and cost of supply is critical, but it won't come at the expense of remaining a safe, responsible employer, neighbor and partner. We demonstrate this through our commitment to sustainable development, stakeholder relations, charitable investments and employee volunteerism. We take great pride in being named to the *Dow Jones Sustainability Index North America* for the ninth consecutive year, in recognition of our focus on sustainable development. The business environment is tough, but we understand our responsibilities on the ground can't come and go. We have a world-class workforce that, despite a very difficult year, has stepped up to industry's challenges. We had to make many difficult decisions, but our commitment to Accountability + Performance, which is rooted in our SPIRIT Values, remains central to our company.

## Major Projects

In 2015, the company achieved startups at seven major projects, including two megaprojects at Australia Pacific LNG (APLNG) in Australia and Surmont 2 in Canada. These projects were the culmination of years of planning and execution across the company and are expected to provide decades of low-decline, low-cost-of-supply production.

Surmont 2

### Our Path Forward

The journey through the price downturn in 2015 was a test for everyone in this industry. Yet, with 2016 only a couple of months underway, we clearly face an even bigger test this year. Our initial 2016 operating plan was premised on oil and natural gas prices similar to those in 2015, but the market changed significantly in a short period of time, driven by two primary factors.

> "The market changed significantly in a short period of time."

The first was commodity prices. Oil prices fell much lower than we and industry expected, with January Brent prices averaging approximately 40 percent lower than average 2015 prices. A global oversupply and weak demand growth continue to contribute to low prices. We now see lower prices persisting throughout 2016, with 2017 as a more likely timeframe for the market to start rebalancing supply and demand. The second factor was an indication that access to credit and debt capacity would tighten significantly across the sector. Both of these factors represent "structural" changes in our assumptions about the outlook for 2016 that require a much more cautious stance in our plans. Accordingly, we recently took several difficult measures in service of maintaining our balance sheet strength as we navigate through this price cycle.

We adjusted our 2016 operating plan, further reducing capital and operating cost guidance by a combined $2 billion. We also made the tough decision to reduce our quarterly dividend, beginning with our first-quarter 2016 payment. This decision was not made lightly. We were not willing to risk our balance sheet in hope of a near-term price recovery. Although difficult, the dividend decision achieves several important objectives for the short, medium and long term. It enables us to conserve cash and protect our balance sheet, while still providing a competitive dividend.

We believe our recent actions were the right ones at the right time, but the business remains challenged. We're vigilantly monitoring the market, staying focused on maintaining our strong balance sheet and delivering on what we can control. We will continue managing our costs and preserving capital flexibility as we adjust to changing conditions and position for an eventual recovery. We don't know when a recovery will occur, but when it does, we believe ConocoPhillips will be in an advantaged position because of our high-quality portfolio and financial strength.

**41%**

**Capital Reduction**
2015 vs. 2014

**14%**

**Operating Cost Reduction**
2015 vs. 2014

**30%**

Safety

**TRR Improvement**
2015 vs. 2014

All of us at ConocoPhillips remain committed to long-term value creation through an approach that returns capital to shareholders, maintains investment discipline and preserves a strong balance sheet. As we continue our journey as an independent E&P, I assure you that we will continue working hard every day to earn and keep your support.

Ryan M. Lance

**Ryan M. Lance**
Chairman and Chief Executive Officer
Feb. 23, 2016

*Use of non-GAAP financial information—This annual report includes non-GAAP financial measures that are included to help facilitate comparisons of company operating performance across periods and with peer companies. A reconciliation determined in accordance with U.S. GAAP is shown on page 8 and at www.conocophillips.com/nongaap.*

# Financial and Operating Highlights

## Financial Highlights

($ Millions, except as indicated)

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| Total revenues and other income | $ 30,935 | 55,517 | 58,248 |
| Net income (loss) atrributable to ConocoPhillips | $ (4,428) | 6,869 | 9,156 |
| Earnings (loss) per share of common stock—diluted (*dollars*) | $ (3.58) | 5.51 | 7.38 |
| Adjusted earnings (loss) | $ (1,724) | 6,609 | 7,061 |
| Adjusted earnings (loss) per share of common stock—diluted (*dollars*) | $ (1.40) | 5.30 | 5.70 |
| Net cash provided by continuing operating activities[1] | $ 7,572 | 16,412 | 15,856 |
| Capital program[2] | $ 10,050 | 17,144 | 16,918 |
| Dividends paid on company common stock | $ 3,664 | 3,525 | 3,334 |
| Total assets | $ 97,484 | 116,539 | 118,057 |
| Total debt | $ 24,880 | 22,565 | 21,662 |
| Total equity | $ 40,082 | 52,273 | 52,492 |
| Percent of total debt to capital | 38% | 30 | 29 |
| Common stockholders' equity | $ 39,762 | 51,911 | 52,090 |
| Common stockholders' equity per share—book value (*dollars*) | $ 32.17 | 42.16 | 42.49 |
| Cash dividends per common share (*dollars*) | $ 2.94 | 2.84 | 2.70 |
| Closing stock price per common share (*dollars*) | $ 46.69 | 69.06 | 70.65 |
| Common shares outstanding at year end (*in thousands*) | 1,235,996 | 1,231,353 | 1,225,939 |
| Average common shares outstanding (*in thousands*) | | | |
| Basic | 1,241,919 | 1,237,325 | 1,230,963 |
| Diluted | 1,241,919 | 1,245,863 | 1,239,803 |

## Operating Highlights

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| **Production[3]** | | | |
| Crude oil production (*MBD*) | 605 | 595 | 581 |
| Natural gas liquids production (*MBD*) | 156 | 159 | 156 |
| Bitumen production (*MBD*) | 151 | 129 | 109 |
| Natural gas production (*MMCFD*) | 4,060 | 3,943 | 3,939 |
| Total production (*MBOED*) | **1,589** | **1,540** | **1,502** |
| **Average Realized Prices[4]** | | | |
| Average crude oil price (*per barrel*) | $ 48.26 | 92.94 | 103.51 |
| Average natural gas liquids price (*per barrel*) | $ 17.79 | 38.71 | 40.79 |
| Average bitumen price (*per barrel*) | $ 18.72 | 55.13 | 53.27 |
| Average natural gas price (*per thousand cubic feet*) | $ 3.96 | 6.48 | 6.00 |
| **Proved Reserves[4]** | | | |
| Crude oil reserves (*MMBOE*) | 2,363 | 2,708 | 2,749 |
| Natural gas liquids reserves (*MMBOE*) | 558 | 715 | 744 |
| Bitumen reserves (*MMBOE*) | 2,393 | 2,066 | 2,030 |
| Natural gas reserves (*BCF*) | 17,193 | 20,500 | 20,388 |
| Total proved reserves (*MMBOE*) | **8,180** | **8,906** | **8,921** |
| **Organic Reserve Replacement Ratio[4,5]** | 10% | 124 | 179 |
| **Acreage[4]** | | | |
| Net developed acreage (*millions of acres*) | 8.8 | 10.9 | 11.3 |
| Net undeveloped acreage (*millions of acres*) | 30.2 | 40.8 | 42.3 |
| Total acreage (*millions of acres*) | **39.0** | **51.7** | **53.6** |

*[1] Certain amounts have been reclassified to conform to current-period presentation.*

*[2] Includes discontinued operations and excludes $2,810 million FCCL prepayment in 2013.*

*[3] Represents continuing operations only. 2015 production was 1,525 MBOED when adjusted for the full-year impact of 2015 asset dispositions, which was 64 MBOED.*

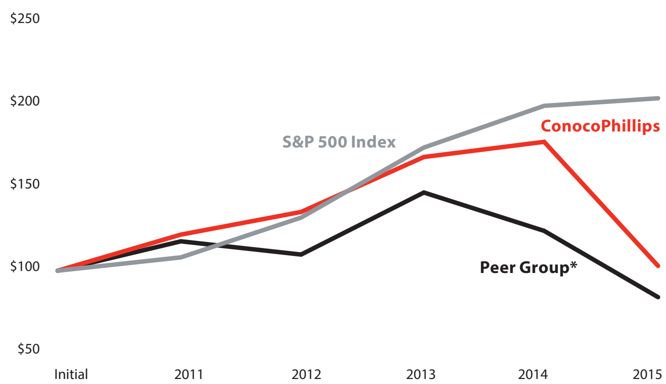
*[4] Includes discontinued operations.*

*[5] Organic reserve replacement ratio excludes the impact of purchases and sales.*

*Use of non-GAAP financial information—This annual report includes non-GAAP financial measures that are included to help facilitate comparisons of company operating performance across periods and with peer companies. A reconciliation determined in accordance with U.S. GAAP is shown on page 8 and at www.conocophillips.com/nongaap.*

## Five-Year Cumulative Total Shareholder Returns

($; Comparison assumes $100 was invested on Dec. 31, 2010 and that all dividends were reinvested)




*Anadarko, Apache, BG Group plc., BP, Chevron, Devon, ExxonMobil, Occidental, Royal Dutch Shell and Total.*

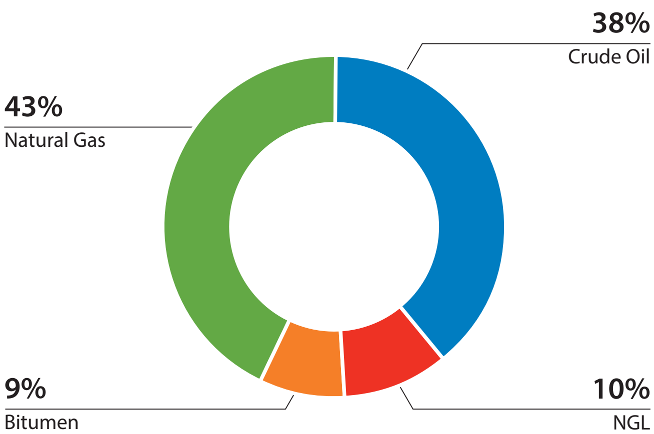
**5%** **Production Growth**[1]

**7** **Major Project Startups**

**$2.2B** **Disposition Proceeds**[2]

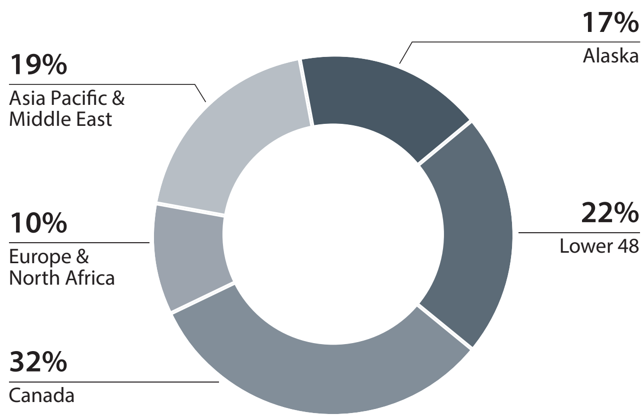
## 2015 Total Production[3]

1,589 MBOED




## 2015 Proved Reserves

8,180 MMBOE




*[1] Production from continuing operations, adjusted for Libya, downtime and dispositions.*
*[2] Includes ~$0.3B from liquidation of certain deferred compensation investments accounted for as cash from investing activities and ~$0.1B from QG3 return of capital.*
*[3] 2015 production was 1,525 MBOED when adjusted for the full-year impact of 2015 asset dispositions, which was 64 MBOED.*

# Board of Directors and Executive Leadership Team

(As of Feb. 23, 2016)

## Board of Directors

**Richard L. Armitage** (4, 5)
President, Armitage International LLC,
Former U.S. Deputy Secretary of State

**Richard H. Auchinleck** (2, 3, 4)
Former President and Chief Executive Officer,
Gulf Canada Resources Limited

**Charles E. Bunch** (1)
Executive Chairman and Former Chief Executive Officer, PPG Industries, Inc.

**James E. Copeland, Jr.** (1, 2)
Former Chief Executive Officer,
Deloitte & Touche and
Deloitte Touche Tohmatsu

**John V. Faraci** (1)
Former Chairman and Chief Executive Officer,
International Paper Company

**Jody Freeman** (3, 5)
Archibald Cox Professor of Law,
Harvard Law School

**Gay Huey Evans, OBE** (1)
Deputy Chairman, The Financial Reporting Council and Non-Executive Director, Bank Itau BBA International Limited and Standard Chartered PLC

**Ryan M. Lance** (2)
Chairman and Chief Executive Officer,
ConocoPhillips

**Arjun N. Murti** (1)
Senior Advisor, Warburg Pincus and
Retired Partner, Goldman, Sachs & Co.

**Robert A. Niblock** (2, 3, 4)
Chairman, President and Chief Executive Officer, Lowe's Companies, Inc.

**Harald J. Norvik** (2, 3, 5)
Former Chairman, President and
Chief Executive Officer, Statoil

1) Member of the Audit and Finance Committee
2) Member of the Executive Committee
3) Member of the Human Resources and Compensation Committee
4) Member of the Directors' Affairs Committee
5) Member of the Public Policy Committee

## Executive Leadership Team*

**Ryan M. Lance**
Chairman and Chief Executive Officer

**Matt J. Fox**
Executive Vice President, Exploration
and Production

**Al J. Hirshberg**
Executive Vice President, Technology and Projects

**Jeff W. Sheets**
Executive Vice President, Finance
and Chief Financial Officer

**Don E. Wallette, Jr.**
Executive Vice President, Commercial,
Business Development and Corporate Planning

**Janet Langford Carrig**
Senior Vice President, Legal, General Counsel
and Corporate Secretary

**Andrew D. Lundquist**
Senior Vice President,
Government Affairs

**Ellen R. DeSanctis**
Vice President, Investor Relations
and Communications

**James D. McMorran**
Vice President, Human Resources and
Real Estate and Facilities Services

** Jeff W. Sheets has elected to retire as executive vice president, Finance and chief financial officer, effective April 1, 2016. The following leadership changes will also take effect on April 1, 2016: Don E. Wallette, Jr. will become executive vice president, Finance, Commercial and chief financial officer; Al J. Hirshberg will become executive vice president, Production, Drilling and Projects; and Matt J. Fox will become executive vice president, Strategy, Exploration and Technology.*

# Shareholder Information

## Annual Meeting

The ConocoPhillips annual meeting of stockholders will be held:

Tuesday, May 10, 2016
Omni Houston Hotel at Westside
13210 Katy Freeway
Houston, TX 77079

Notice of the meeting and proxy materials are being sent to all shareholders.

## Direct Stock Purchase and Dividend Reinvestment Plan

The ConocoPhillips Investor Services Program is a direct stock purchase and dividend reinvestment plan that offers shareholders a convenient way to buy additional shares and reinvest their common stock dividends. Purchases of company stock through direct cash payment are commission free. Please call Computershare to request an enrollment package:

Toll-free number: 800-356-0066

You may also enroll online at:
*www.computershare.com/investor.*
Registered shareholders can access important investor communications online and sign up to receive future shareholder materials electronically by following the enrollment instructions.

## Principal and Registered Offices

600 N. Dairy Ashford Road
Houston, TX 77079

2711 Centerville Road
Wilmington, DE 19808

## Stock Transfer Agent and Registrar

Computershare
211 Quality Circle, Suite 210
College Station, TX 77845
*www.computershare.com*

## Information Requests

For information about dividends and certificates, or to request a change of address form, shareholders may contact:

Computershare
P.O. Box 30170
College Station, TX 77842-3170
Toll-free number: 800-356-0066
Outside the U.S.: 201-680-6578
TDD for hearing impaired: 800-231-5469
TDD outside the U.S.: 201-680-6610
*www.computershare.com/investor*

Personnel in the following offices can also answer investors' questions about the company:

**Institutional Investors:**
ConocoPhillips Investor Relations
600 N. Dairy Ashford Road
Houston, TX 77079
281-293-5000
*investor.relations@conocophillips.com*

**Individual Investors:**
ConocoPhillips Shareholder Relations
600 N. Dairy Ashford Road, ML3080
Houston, TX 77079
281-293-6800
*shareholder.relations@conocophillips.com*

## Compliance and Ethics

For guidance, or to express concerns or ask questions about compliance and ethics issues, call the ConocoPhillips Ethics Helpline toll-free at 877-327-2272, available 24 hours a day, seven days a week. The ethics office also may be contacted via email at *ethics@conocophillips.com*, the Internet at *www.conocophillips.ethicspoint.com* or by writing:

Attn: Corporate Ethics Office
ConocoPhillips
600 N. Dairy Ashford Road, ML3170
Houston, TX 77079

## Copies of Annual Report and Proxy Statement

Copies of this annual report and the proxy statement, as filed with the U.S. Securities and Exchange Commission, are available for free by making a request on the company's website, calling 918-661-3700 or writing:

ConocoPhillips Reports
B-13 Plaza Office Building
315 Johnstone Ave.
Bartlesville, OK 74004

## Website

***www.conocophillips.com***
The site includes resources of interest to investors, including news releases and presentations to securities analysts; copies of ConocoPhillips' annual reports and proxy statements; reports to the U.S. Securities and Exchange Commission; and data on ConocoPhillips' health, safety and environmental performance.

# Non-GAAP Reconciliation

## Adjusted Earnings

($ Millions, except as indicated)

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| **Net Income (Loss) Attributable to ConocoPhillips** | **$ (4,428)** | 6,869 | 9,156 |
| Adjustments | | | |
| Net gain on asset sales | (395) | (38) | (1,075) |
| Impairments | 3,077 | 641 | 269 |
| Loss on capacity agreements | — | 83 | — |
| Qatar depreciation adjustment | — | 28 | — |
| International tax law changes | (426) | — | — |
| Restructuring | 282 | — | — |
| Pending claims and settlements | 62 | (268) | (118) |
| Tax impact from country exit | (28) | — | — |
| Pension settlement expense | 143 | — | 41 |
| Rig termination | 246 | — | — |
| Depreciation volume adjustment | (48) | — | — |
| Tax benefit on interest expense | (209) | (61) | — |
| Deferred tax adjustment | — | (59) | — |
| Freeport LNG termination agreement | — | 545 | — |
| Discontinued operations—Other[1] | — | (1,131) | (1,178) |
| FCCL IFRS depreciation adjustment | — | — | (33) |
| Tax loss carryforward utilization | — | — | (1) |
| **Adjusted Earnings (Loss)** | **$ (1,724)** | 6,609 | 7,061 |
| Earnings (loss) per share of common stock—diluted (*dollars*) | $ (3.58) | 5.51 | 7.38 |
| Adjusted earnings (loss) per share of common stock—diluted (*dollars*) | $ (1.40) | 5.30 | 5.70 |

## Operating Costs

($ Millions, except as indicated)

| | 2015 | 2014 |
|---|---|---|
| Production and operating expenses | $ 7,016 | 8,909 |
| Selling, general and administrative expenses | 953 | 735 |
| Exploration expenses excluding dry holes and leasehold impairment* | 1,127 | 879 |
| **Operating Costs** | **$ 9,096** | 10,523 |
| **Operating Costs—Percent Reduction** | **-14%** | — |
| | | |
| Exploration expenses | $ 4,192 | 2,045 |
| Less dry holes | 1,141 | 604 |
| Less leasehold impairment | 1,924 | 562 |
| ***Exploration Expenses Excluding Dry Holes and Leasehold Impairment** | **$ 1,127** | 879 |

[1] *Includes Kashagan, Algeria and Nigeria.*

# 2015

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

# Form 10-K

(Mark One)

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2015**

OR

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

For the transition period from ____________________ to ____________________

Commission file number: **001-32395**

# ConocoPhillips

*(Exact name of registrant as specified in its charter)*

| | |
|---|---|
| **Delaware** | **01-0562944** |
| *(State or other jurisdiction of incorporation or organization)* | *(I.R.S. Employer Identification No.)* |

**600 North Dairy Ashford**
**Houston, TX 77079**
*(Address of principal executive offices) (Zip Code)*

Registrant's telephone number, including area code: **281-293-1000**

Securities registered pursuant to Section 12(b) of the Act:

| Title of each class | Name of each exchange on which registered |
|---|---|
| Common Stock, $.01 Par Value | New York Stock Exchange |
| 6.65% Debentures due July 15, 2018 | New York Stock Exchange |
| 7% Debentures due 2029 | New York Stock Exchange |

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. [x] Yes [ ] No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. [ ] Yes [x] No

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). [x] Yes [ ] No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

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

Large accelerated filer [x] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

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

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $61.41, was $75.7 billion.

The registrant had 1,236,202,726 shares of common stock outstanding at January 31, 2016.

**Documents incorporated by reference:**
Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 10, 2016 (Part III)

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## PART I

Unless otherwise indicated, "the company," "we," "our," "us" and "ConocoPhillips" are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Items 1 and 2—Business and Properties, contain forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. 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 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 the heading "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 72.

### Items 1 and 2. BUSINESS AND PROPERTIES

### CORPORATE STRUCTURE

ConocoPhillips is the world's largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. ConocoPhillips was incorporated in the state of Delaware on November 16, 2001, in connection with, and in anticipation of, the merger between Conoco Inc. and Phillips Petroleum Company. The merger between Conoco and Phillips was consummated on August 30, 2002.

In April 2012, the ConocoPhillips Board of Directors approved the separation of our downstream business into an independent, publicly traded energy company, Phillips 66. Each ConocoPhillips stockholder received one share of Phillips 66 stock for every two shares of ConocoPhillips stock held at the close of business on the record date of April 16, 2012. The separation was completed on April 30, 2012, and activities related to Phillips 66 have been treated as discontinued operations for all periods prior to the separation.

In 2012, we agreed to sell our interest in the North Caspian Sea Production Sharing Agreement (Kashagan) and our Nigeria and Algeria businesses (collectively, the "Disposition Group"). We sold our Nigeria business in the third quarter of 2014, and we sold Kashagan and our Algeria business in the fourth quarter of 2013. Results for the Disposition Group have been reported as discontinued operations in all periods presented. For additional information on all discontinued operations, see Note 3—Discontinued Operations, in the Notes to Consolidated Financial Statements.

Headquartered in Houston, Texas, we have operations and activities in 21 countries. Our key focus areas include safely operating producing assets, executing major developments and exploring for new resources in promising areas. Our portfolio includes resource-rich North American tight oil and oil sands assets; lower-risk legacy assets in North America, Europe, Asia and Australia; several major international developments; and an inventory of global conventional and unconventional exploration prospects.

At December 31, 2015, ConocoPhillips employed approximately 15,900 people worldwide.

We are marketing certain non-core assets across all of our segments. For additional information on asset sales, see the "Outlook" section of Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

## SEGMENT AND GEOGRAPHIC INFORMATION

Effective November 1, 2015, the Other International and historically presented Europe segments were restructured to align with changes to our internal organization structure. The Libya business was moved from the Other International segment to the historically presented Europe segment, which is now renamed Europe and North Africa. Accordingly, results of operations for the Other International and Europe and North Africa segments have been revised in all periods presented. There was no impact on our consolidated financial statements, and the impact on our segment presentation is immaterial. For operating segment and geographic information, see Note 24—Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

We explore for, produce, transport and market crude oil, bitumen, natural gas, liquefied natural gas (LNG) and natural gas liquids on a worldwide basis. At December 31, 2015, our continuing operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, and Qatar.

The information listed below appears in the "Oil and Gas Operations" disclosures following the Notes to Consolidated Financial Statements and is incorporated herein by reference:

- Proved worldwide crude oil, natural gas liquids, natural gas and bitumen reserves.
- Net production of crude oil, natural gas liquids, natural gas and bitumen.
- Average sales prices of crude oil, natural gas liquids, natural gas and bitumen.
- Average production costs per barrel of oil equivalent (BOE).
- Net wells completed, wells in progress and productive wells.
- Developed and undeveloped acreage.

The following table is a summary of the proved reserves information included in the "Oil and Gas Operations" disclosures following the Notes to Consolidated Financial Statements. Approximately 84 percent of our proved reserves are located in politically stable countries that belong to the Organization for Economic Cooperation and Development. Natural gas reserves are converted to BOE based on a 6:1 ratio: six thousand cubic feet (MCF) of natural gas converts to one BOE. See Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance the understanding of the following summary reserves table.

| Net Proved Reserves at December 31 | Millions of Barrels of Oil Equivalent 2015 | 2014 | 2013 |
|---|---|---|---|
| Crude oil | | | |
| Consolidated operations | **2,270** | 2,605 | 2,659 |
| Equity affiliates | **93** | 103 | 90 |
| Total Crude Oil | **2,363** | 2,708 | 2,749 |
| Natural gas liquids | | | |
| Consolidated operations | **508** | 662 | 699 |
| Equity affiliates | **50** | 53 | 45 |
| Total Natural Gas Liquids | **558** | 715 | 744 |
| Natural gas | | | |
| Consolidated operations | **1,988** | 2,543 | 2,710 |
| Equity affiliates | **878** | 874 | 688 |
| Total Natural Gas | **2,866** | 3,417 | 3,398 |
| Bitumen | | | |
| Consolidated operations | **687** | 598 | 579 |
| Equity affiliates | **1,706** | 1,468 | 1,451 |
| Total Bitumen | **2,393** | 2,066 | 2,030 |
| Total consolidated operations | **5,453** | 6,408 | 6,647 |
| Total equity affiliates | **2,727** | 2,498 | 2,274 |
| Total company | **8,180** | 8,906 | 8,921 |

Total production from continuing operations was 1,589 thousand barrels of oil equivalent per day (MBOED) in 2015, compared with 1,540 MBOED, including Libya, in 2014, an increase of 3 percent. The increase in total average production in 2015 primarily resulted from additional production from major developments, including tight oil plays in the Lower 48; Gumusut in Malaysia; APLNG in Australia; Greater Britannia projects and the J-Area in the U.K.; and the ramp-up of Foster Creek Phase F in Canada. Improved well performance, mostly in the Lower 48, western Canada and Norway, and lower turnaround activity also contributed to higher production in 2015. These increases were largely offset by normal field decline. Production from continuing operations was 1,589 MBOED in 2015, compared with 1,532 MBOED in 2014, excluding Libya, an increase of 57 MBOED, or 4 percent. Full-year production from assets sold or under agreement in 2015 was 64 MBOED.

Our total average realized price from continuing operations was $34.34 per BOE in 2015, a decrease of 47 percent compared with $64.59 per BOE in 2014, which reflected lower average realized prices across all commodities. Our worldwide annual average crude oil price from continuing operations decreased 48 percent in 2015, from $92.80 per barrel in 2014 to $48.26 per barrel in 2015. Additionally, our worldwide annual average natural gas liquids prices from continuing operations decreased 54 percent, from $38.99 per barrel in 2014 to $17.79 per barrel in 2015. Our worldwide annual average natural gas price from continuing operations decreased 40 percent, from $6.57 per MCF in 2014 to $3.96 per MCF in 2015. Average annual bitumen prices also decreased 66 percent, from $55.13 per barrel in 2014 to $18.72 per barrel in 2015.

ALASKA

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids, natural gas and LNG. We are the largest crude oil and natural gas producer in Alaska and have major ownership interests in two of North America's largest oil fields located on Alaska's North Slope: Prudhoe Bay and Kuparuk. We also have a significant operating interest in the Alpine Field, located on the Western North Slope. Additionally, we are one of Alaska's largest owners of state and federal exploration leases, with approximately 0.7 million net undeveloped acres at year-end 2015. Approximately 0.4 million of these acres are located in the National Petroleum Reserve—Alaska (NPRA) and the North Slope, and 0.3 million are located in the Chukchi Sea. In 2015, Alaska operations contributed 19 percent of our worldwide liquids production and 1 percent of our natural gas production.

| | | | 2015 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD* | Natural Gas MMCFD** | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Greater Prudhoe Area | 36.1% | BP | 90 | 10 | 92 |
| Greater Kuparuk Area | 52.2–55.5 | ConocoPhillips | 51 | - | 51 |
| Western North Slope | 78.0 | ConocoPhillips | 30 | 1 | 30 |
| Cook Inlet Area | 33.3–100.0 | ConocoPhillips | - | 31 | 5 |
| Total Alaska | | | 171 | 42 | 178 |

**Thousands of barrels per day.*
***Millions of cubic feet per day.*

*Greater Prudhoe Area*
The Greater Prudhoe Area includes the Prudhoe Bay Field and five satellite fields, as well as the Greater Point McIntyre Area fields. Prudhoe Bay, the largest oil field on Alaska's North Slope, is the site of a large waterflood and enhanced oil recovery operation, as well as a gas plant which processes natural gas to recover natural gas liquids before reinjection into the reservoir. Prudhoe Bay's satellites are Aurora, Borealis, Polaris, Midnight Sun and Orion, while the Point McIntyre, Niakuk, Raven and Lisburne fields are part of the Greater Point McIntyre Area.

*Greater Kuparuk Area*
We operate the Greater Kuparuk Area, which consists of the Kuparuk Field and four satellite fields: Tarn, Tabasco, Meltwater and West Sak. Kuparuk is located 40 miles west of Prudhoe Bay. Field installations include three central production facilities which separate oil, natural gas and water, as well as a separate seawater treatment plant. Development drilling at Kuparuk consists of rotary-drilled wells and horizontal multi-laterals from existing well bores utilizing coiled-tubing drilling.

Drill Site 2S, in the southwestern area of the Kuparuk Field, was sanctioned in October 2014. First oil was achieved in October 2015 with net peak production estimated at 5 MBOED in 2016.

The 1H Northeast West Sak (NEWS) oil development targeting the West Sak reservoir in the Kuparuk River Unit, was sanctioned in March 2015. First production is anticipated in 2017.

*Western North Slope*
On the Western North Slope, we operate the Colville River Unit, which includes the Alpine Field and three satellite fields: Nanuq, Fiord and Qannik. Alpine is located 34 miles west of Kuparuk. In October 2015, first oil was achieved at Alpine West CD5, a new drill site which extends the Alpine reservoir west into the NPRA. Net peak production is estimated at 10 MBOED in 2016.

The Greater Mooses Tooth Unit, the first unit established entirely within the NPRA, was formed in 2008. In 2015, we received permit approvals and sanctioning from the regulatory agencies for the Greater Mooses Tooth #1 (GMT1) drill site. GMT1 is planned to be connected by road to the CD5 drill site, and production will be transported by pipeline to the existing Alpine facilities for processing. We are evaluating further exploration and development potential in the NPRA.

*Cook Inlet Area*

We operate the North Cook Inlet Unit, the Beluga River Unit, and the Kenai LNG Facility in the Cook Inlet Area. We have a 100 percent interest in the North Cook Inlet Unit and the Kenai LNG Facility, while we own 33.3 percent of the Beluga River Unit. Our share of production from the units is primarily sold to local utilities and is also used to supply feedstock to the Kenai LNG Plant.

The Kenai LNG Facility includes a 1.6 million-tons-per-year capacity plant, as well as docking and loading facilities for LNG tankers. LNG from the plant has historically been transported and sold to utility companies in Japan. The plant was idled in late-2012; however, due to a change in market conditions, including additional gas supplies, we were granted a two-year export license from the U.S. Department of Energy (DOE) in April 2014 to export up to 40 billion cubic feet of LNG from the facility. As a result, we shipped six cargoes of LNG from the Kenai Facility to Asia in 2015. In February 2016, our export license was renewed for an additional two years.

In the first quarter of 2016, we entered into an agreement to sell our interest in the Beluga River Unit natural gas field in the Cook Inlet Area. The transaction is expected to close in the second quarter of 2016.

*Point Thomson*

We own a 5 percent interest in the Point Thomson Unit, which is located approximately 60 miles east of Prudhoe Bay. An initial production system is anticipated to be online by second quarter 2016, which is estimated to send 400 net barrels of oil equivalent per day (BOED) of condensate through the Trans-Alaska Pipeline System (TAPS).

*Alaska LNG (AKLNG)*

During 2012, we, along with affiliates of Exxon Mobil Corporation, BP p.l.c. and TransCanada Corporation (collectively, the "AKLNG co-venturers"), began evaluating a potential LNG project which would liquefy and export natural gas from Alaska's North Slope and deliver it to market. The AKLNG Project concept is an integrated LNG project consisting of a liquefaction plant, including marine terminal facilities and auxiliary marine vessels, located in south-central Alaska; a natural gas treatment plant, located on the North Slope; and an estimated 800-mile natural gas pipeline, which would connect the two plants.

The proposed AKLNG natural gas liquefaction plant and terminal would be located in the Nikiski area on the Kenai Peninsula, approximately 60 miles southwest of Anchorage, along the Cook Inlet. In January 2014, the AKLNG co-venturers, the Commissioners of the Alaska Departments of Revenue and Natural Resources, and the Alaska Gasline Development Corporation (AGDC), a state-owned corporation, signed a Heads of Agreement (HOA) for the AKLNG Project. The HOA provides a roadmap of how the parties intend to progress the project, including proposed terms for participation by the State of Alaska as an equity owner, proposed fiscal and regulatory terms, and proposed terms for expansion of project components. During 2014, general legislation was enacted by the State of Alaska, and a joint venture agreement for the preliminary front-end engineering and design phase of the project was executed. The AKLNG Project will require several major federal permits, and in July 2014, an application for an LNG export license was filed with the U.S. DOE to export up to 20 million metric tons a year of LNG for 30 years. In November 2014 and June 2015, the U.S. DOE authorized the export of LNG to free trade agreement (FTA) and non-FTA countries, respectively. In September 2014, the Federal Energy Regulatory Commission (FERC) accepted the project into pre-file status, which initiates the lengthy environmental and safety reviews required to design, permit, construct and operate the plants and pipeline. In March 2015, the FERC issued their Notice of Intent (NOI) to prepare the Environmental Impact Statement for AKLNG and begin the National Environmental Policy Act period to seek public comment. In October 2015, the Alaska Oil and Gas Conservation Commission (AOGCC) issued orders for gas offtake at Prudhoe Bay and Point Thomson. In December 2015, AGDC acquired the interest in the AKLNG Project previously held by TransCanada Corporation. On December 31, 2015 the HOA expired by its own terms. Commercial negotiations and planning for front-end engineering and design are ongoing.

Significant engineering, technical, regulatory, fiscal, commercial and permitting issues would need to be resolved prior to a final investment decision on the potential $45 billion to $65 billion (gross) project.

*Exploration*
We plan to drill two to three exploration wells in 2016 in the NPRA.

Our plans to drill an exploration well in the Chukchi Sea have been cancelled due to the current market environment, regulatory uncertainty and expiry of the primary lease term in 2020. As a result, we recorded a $406 million after-tax charge for leasehold and capitalized interest impairment and dry hole expense in the fourth quarter of 2015.

*Transportation*
We transport the petroleum liquids produced on the North Slope to south central Alaska through an 800-mile pipeline that is part of TAPS. We have a 29.1 percent ownership interest in TAPS, and we also have ownership interests in the Alpine, Kuparuk and Oliktok pipelines on the North Slope.

Our wholly owned subsidiary, Polar Tankers, Inc., manages the marine transportation of our North Slope production, using five company-owned, double-hulled tankers, and charters third-party vessels as necessary. The tankers primarily deliver oil from Valdez, Alaska, to refineries on the west coast of the United States.

## LOWER 48

The Lower 48 segment consists of operations located in the U.S. Lower 48 states and exploration activities in the Gulf of Mexico. The Lower 48 business is organized within three regions covering the Gulf Coast, Mid-Continent and Rockies. As a result of tight oil opportunities, we have directed our investments toward certain shorter cycle time, low cost-of-supply plays. In July 2015, we announced our plan to reduce future deepwater exploration spending and terminated our Gulf of Mexico deepwater drillship contract with Ensco. We hold 14.3 million net onshore and offshore acres in the Lower 48. In 2015, the Lower 48 contributed 33 percent of our worldwide liquids production and 36 percent of our natural gas production.

| | | | 2015 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Eagle Ford | Various % | Various | 139 | 208 | 174 |
| Gulf of Mexico | Various | Various | 12 | 12 | 14 |
| Gulf Coast—Other | Various | Various | 8 | 182 | 38 |
| Total Gulf Coast | | | 159 | 402 | 226 |
| Permian | Various | Various | 42 | 122 | 62 |
| Barnett | Various | Various | 5 | 41 | 12 |
| Anadarko Basin | Various | Various | 6 | 109 | 24 |
| Total Mid-Continent | | | 53 | 272 | 98 |
| Bakken | Various | Various | 54 | 44 | 61 |
| Wyoming/Uinta | Various | Various | - | 95 | 16 |
| Niobrara | Various | Various | 5 | 2 | 5 |
| San Juan | Various | Various | 29 | 657 | 139 |
| Total Rockies | | | 88 | 798 | 221 |
| Total U.S. Lower 48 | | | 300 | 1,472 | 545 |

*Onshore*
We hold 12.4 million net acres of onshore conventional and unconventional acreage in the Lower 48, the majority of which is either held by production or owned by the company. Our unconventional holdings total approximately 2.6 million net acres in the following areas:

- 900,000 net acres in the San Juan Basin, located in northwestern New Mexico and southwestern Colorado.
- 617,000 net acres in the Bakken, located in North Dakota and eastern Montana.
- 216,000 net acres in the Eagle Ford, located in South Texas.
- 109,000 net acres in the Niobrara, located in northeastern Colorado.
- 102,000 net acres in the Permian, located in West Texas and southeastern New Mexico.
- 61,000 net acres in the Barnett, located in north central Texas.
- 553,000 net acres in other unconventional exploration plays.

The majority of our 2015 onshore production originated from the Eagle Ford, San Juan, Permian and Bakken. Onshore activities in 2015 were centered mostly on continued development of emerging and existing assets, with an emphasis on areas with low cost of supply, particularly in growing unconventional plays. The 2015 drilling activity levels declined relative to 2014 due to reduced capital spending in the low commodity price environment. Our major focus areas in 2015 included the following:

- Eagle Ford—The Eagle Ford continued full field development in 2015, with the majority of the development program being drilled on multi-well pads. We operated six rigs on average in 2015, resulting in 136 operated wells drilled and 150 operated wells brought online. In 2015, we also increased production by 12 percent compared with 2014 and achieved net peak production of 190 MBOED, compared with 179 MBOED in 2014.
- Bakken—We operated five rigs on average throughout the year in the Bakken. We continued our pad drilling efficiency, drilling 89 operated wells during the year and bringing 128 operated wells online. As a result, we achieved net peak production of 80 MBOED in 2015, compared with 63 MBOED in 2014.
- San Juan Basin—The San Juan Basin includes significant conventional gas production, which yields approximately 20 percent natural gas liquids, as well as the majority of our U.S. coalbed methane (CBM) production. We hold approximately 1.3 million net acres of oil and gas leases by production in San Juan, where we continue to pursue select conventional development opportunities. This also includes approximately 900,000 net unconventional acres of lease rights.
- Permian Basin—The Permian Basin is another area where we are leveraging our conventional legacy position by utilizing new technology to improve the ultimate recovery and value from these fields. This technology should also identify new, unconventional plays across the region. We hold approximately 1.0 million net acres in the Permian, which includes 102,000 net unconventional acres.

In the fourth quarter of 2015, we completed the sale of certain non-core assets in East Texas and North Louisiana and South Texas. Production from the assets sold was 33 MBOED, approximately 6 percent of the total Lower 48 segment production in 2015.

*Gulf of Mexico*
At year-end 2015, our portfolio of producing properties in the Gulf of Mexico primarily consisted of one operated field and three fields operated by co-venturers, including:

- 75 percent operated working interest in the Magnolia Field in Garden Banks Blocks 783 and 784.
- 15.9 percent nonoperated working interest in the unitized Ursa Field located in the Mississippi Canyon Area.
- 15.9 percent nonoperated working interest in the Princess Field, a northern subsalt extension of the Ursa Field.
- 12.4 percent nonoperated working interest in the unitized K2 Field, comprised of seven blocks in the Green Canyon Area.

*Exploration*

- *Conventional Exploration*
  In the third quarter of 2015, we decided not to conduct further activity on certain Gulf of Mexico leases. At December 31, 2015, we held approximately 1.8 million net acres in the deepwater Gulf of Mexico.

  During 2015, we conducted appraisal drilling at Shenandoah, Tiber, and Gila. The nonoperated Gibson exploration and Tiber appraisal wells, and the ConocoPhillips operated Melmar exploration well are currently drilling.

  We own a 30 percent nonoperated working interest in the Shenandoah discovery, which was announced in 2009. The third Shenandoah down dip appraisal well was spud in 2015, and planning is underway for the next appraisal well, which is expected to spud in the first half of 2016.

  The operated Harrier and nonoperated Vernaccia wells were expensed as dry holes in 2015. The operator of the Gila prospect has elected to discontinue exploration and appraisal activity. Accordingly, we recorded $111 million in after-tax dry hole expense for a previously suspended well in the Gila prospect, and a $100 million charge for the impairment of undeveloped leasehold costs.

- *Unconventional Exploration*
  Our onshore focus areas include the Niobrara in the Denver-Julesburg Basin and the Wolfcamp and Bone Springs in the Delaware Basin, as well as several emerging plays. In 2015, we drilled 21 unconventional wells in the Delaware Basin. We continue to assess and appraise this and other unconventional opportunities.

**Facilities**

*Freeport LNG Terminal*

In July 2013, we agreed with Freeport LNG Development, L.P. to terminate our long-term agreement to use 0.9 billion cubic feet per day of regasification capacity at Freeport's 1.5 billion cubic-feet-per-day LNG receiving terminal in Quintana, Texas. The termination agreement conditions were satisfied in 2014. Our terminal regasification capacity has been reduced from 0.9 billion cubic feet per day to 0.4 billion cubic feet per day until July 1, 2016, at which time it will be reduced to zero. As a result of this transaction, we anticipate saving approximately $50 to $60 million per year in costs over the next 17 years. For additional information, see Note 7—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

*Golden Pass LNG Terminal*

We have a 12.4 percent ownership interest in the Golden Pass LNG Terminal and affiliated Golden Pass Pipeline, with a combined net book value of approximately $273 million at December 31, 2015. It is located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal became commercially operational in May 2011. We hold terminal and pipeline capacity for the receipt, storage and regasification of the LNG purchased from Qatar Liquefied Gas Company Limited (3) (QG3) and the transportation of regasified LNG to interconnect with major interstate natural gas pipelines. Utilization of the terminal has been and is expected to be limited, as market conditions currently favor the flow of LNG to European and Asian markets. As a result, we are evaluating opportunities to optimize the value of the terminal facilities.

*Great Northern Iron Ore Properties Trust*

We hold the interest in the Great Northern Iron Ore Properties trust (the Trust), a grantor trust that owns mineral and surface interests in the Mesabi Iron Range in northeastern Minnesota and certain other personal property. Pursuant to the terms of the Trust Agreement, the Trust terminated on April 6, 2015. At the end of the wind-down period, documents memorializing our ownership of certain Trust property, including all of the

Trust's mineral properties and active leases, will be delivered to us. The Trustees currently anticipate the wind-down process, final distribution and dissolution of the Trust will be completed by the end of 2016. At that time, we expect to recognize the fair value of the Trust's net assets transferred to us.

*Other*

- San Juan Gas Plant—We operate and own a 50 percent interest in the San Juan Gas Plant, a 550 million cubic-feet-per-day capacity natural gas processing plant in Bloomfield, New Mexico.
- Lost Cabin Gas Plant—We operate and own a 46 percent interest in the Lost Cabin Gas Plant, a 313 million cubic-feet-per-day capacity natural gas processing facility in Lysite, Wyoming.
- Helena Condensate Processing Facility—We operate and own the Helena Condensate Processing Facility, a 90,000 barrel-per-day condensate processing plant located in Kenedy, Texas.
- Sugarloaf Condensate Processing Facility—We operate and own an 87.5 percent interest in the Sugarloaf Condensate Processing Facility, a 30,000 barrel-per-day condensate processing plant located near Pawnee, Texas.
- Bordovsky Condensate Processing Facility—We operate and own the Bordovsky Condensate Processing Facility, a 15,000 barrel-per-day condensate processing plant located in Kenedy, Texas.

CANADA

Our Canadian operations mainly consist of natural gas fields in western Canada and oil sands developments in the Athabasca Region of northeastern Alberta. In 2015, operations in Canada contributed 21 percent of our worldwide liquids production and 18 percent of our natural gas production.

| | | | 2015 | | | |
|---|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Bitumen MBD | Total MBOED |
| **Average Daily Net Production** | | | | | | |
| Western Canada | Various% | Various | 38 | 715 | - | 157 |
| Surmont | 50.0 | ConocoPhillips | - | - | 13 | 13 |
| Foster Creek | 50.0 | Cenovus | - | - | 65 | 65 |
| Christina Lake | 50.0 | Cenovus | - | - | 73 | 73 |
| Total Canada | | | 38 | 715 | 151 | 308 |

*Western Canada*

Our operations in western Canada extend across Alberta and British Columbia. We operate or have ownership interests in approximately 50 natural gas processing plants in the region, and, as of December 31, 2015, held leasehold rights in 3.2 million net acres in western Canada. Our investments in 2015 were focused mainly on opportunities in the following three core development areas:

- Deep Basin—We hold leasehold rights in 1.4 million net acres in the Deep Basin, located in northwest Alberta and northeast British Columbia. In 2015, Deep Basin achieved average net production of 48 MBOED, and we drilled 13 horizontal wells.
- Kaybob-Edson—We hold leasehold rights in 0.8 million net acres in the Kaybob-Edson Area, located south of the Deep Basin in west central Alberta. Net production for Kaybob-Edson averaged 45 MBOED in 2015, and we drilled 15 horizontal wells.
- Clearwater—Located in west central Alberta, south of Kaybob-Edson, we hold 0.9 million net acres of leasehold rights. In 2015, average net production for Clearwater was 40 MBOED, and we drilled 11 horizontal wells.

Assets located outside these development areas are focused on production optimization. In the fourth quarter of 2015, we finalized sales of certain non-core assets in British Columbia, Saskatchewan and Alberta. Production from the assets sold was 27 MBOED, approximately 9 percent of the total Canada segment production in 2015. At December 31, 2015, the company held 0.1 million net acres of leasehold rights in these areas.

*Oil Sands*
We hold approximately 0.9 million net acres of land in the Athabasca Region of northeastern Alberta. Our bitumen resources in Canada are produced via an enhanced thermal oil recovery method called steam-assisted gravity drainage (SAGD), whereby steam is injected into the reservoir, effectively liquefying the heavy bitumen, which is recovered and pumped to the surface for further processing.

- Surmont—The Surmont oil sands leases are located approximately 35 miles south of Fort McMurray, Alberta. Surmont is a 50/50 joint venture with Total S.A. Surmont 2 construction began in 2010, and achieved first production in the third quarter of 2015. Surmont's gross production capacity is estimated to be 150 MBOED.
- FCCL— FCCL Partnership, a Canadian upstream general partnership, is a 50/50 heavy oil business venture with Cenovus Energy Inc. FCCL's assets are operated by Cenovus and include the Foster Creek, Christina Lake and Narrows Lake SAGD bitumen developments. FCCL continues to progress development plans for each of these assets, including near-term completion of phase expansions as detailed below:

    - *Foster Creek*
      Foster Creek is located approximately 200 miles northeast of Edmonton, Alberta. There are six producing phases at Foster Creek, Phases A through F, with construction continuing on Phase G. Net production at Foster Creek increased approximately 12 MBOED, mainly as a result of a continued ramp up toward full capacity. In the fourth quarter of 2014, FCCL received regulatory approval for Phase J.

    - *Christina Lake*
      Christina Lake is located approximately 75 miles south of Fort McMurray, Alberta. There are five producing phases at Christina Lake, Phases A through E, with construction continuing on Phase F. In late 2015, an optimization project was completed at Christina Lake that increased gross production capacity to 160 MBOED, with incremental production expected to ramp up during 2016. In the fourth quarter of 2015, regulatory approval was received for Phase H development.

    - *Narrows Lake*
      Narrows Lake Phase A, was sanctioned in late 2012 and is expected to have 45 MBOED of production capacity; however, construction has been deferred.

*Exploration*
We hold exploration acreage in four areas of Canada: onshore western Canada, offshore eastern Canada, the Mackenzie Delta/Beaufort Sea Region and the Arctic Islands. Our primary exploration focus is on unconventional plays in western Canada and conventional exploration offshore eastern Canada.

- *Conventional Exploration*
  During 2014, we entered into a farm-in agreement to acquire a 30 percent nonoperated interest in six exploration licenses covering approximately five million gross acres in the deepwater Shelburne Basin, offshore Nova Scotia. In the fourth quarter of 2015, we spudded the first of two exploration well commitments in offshore Nova Scotia. The second exploration well is anticipated to begin drilling in the second quarter of 2016. In December 2014, we participated in a successful bid for one

exploration license covering 0.7 million gross acres located in the Flemish Pass Basin, offshore Newfoundland. In January 2015, we were awarded the license, in which we hold a 30 percent nonoperated interest. Seismic surveys of the subsurface were completed in 2015.

- *Unconventional Exploration*
  We hold approximately 0.7 million net acres in the emerging Montney, Muskwa, Duvernay and Canol unconventional plays in Alberta, northeastern British Columbia and the Northwest Territories. During 2015, we completed a lease swap and continued to drill exploration and appraisal wells in the Montney play, which extends from British Columbia into Alberta.

In the fourth quarter of 2015, we recorded dry hole expense of $185 million after-tax associated with our Horn River, Northwest Territories, Thornbury and Saleski properties, and an impairment charge of $75 million after-tax for unproved properties in the Duvernay, Thornbury, Saleski and Crow Lake areas.

EUROPE AND NORTH AFRICA

The Europe and North Africa segment consists of operations and exploration activities in Norway, the United Kingdom and Libya. In 2015, operations in Europe and North Africa contributed 14 percent of our worldwide liquids production and 12 percent of natural gas production.

**Norway**

| | | | 2015 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Greater Ekofisk Area | 35.1% | ConocoPhillips | 57 | 51 | 66 |
| Alvheim | 20.0 | Det norske oljeselskap | 9 | 9 | 11 |
| Heidrun | 24.0 | Statoil | 12 | 13 | 14 |
| Other | Various | Statoil | 15 | 80 | 28 |
| Total Norway | | | 93 | 153 | 119 |

The Greater Ekofisk Area is located approximately 200 miles offshore Stavanger, Norway in the North Sea, and comprises three producing fields: Ekofisk, Eldfisk and Embla. Crude oil is exported to Teesside, England, and the natural gas is exported to Emden, Germany. Ekofisk South achieved first production in 2013, while Eldfisk II achieved startup in January 2015. Continued development drilling in the Greater Ekofisk Area will contribute additional production over the coming years, as additional wells come online.

The Alvheim development is located in the northern part of the North Sea and consists of a floating production, storage and offloading (FPSO) vessel and subsea installations. Produced crude oil is exported via shuttle tankers, and natural gas is transported to the Scottish Area Gas Evacuation (SAGE) terminal at St. Fergus, Scotland, through the SAGE pipeline.

The Heidrun Field is located in the Norwegian Sea. Produced crude oil is stored in a floating storage unit and exported via shuttle tankers. Part of the natural gas is currently injected into the reservoir for optimization of crude oil production, while the remainder is used as feedstock in a methanol plant in Norway, in which we own an 18 percent interest.

We also have varying ownership interests in five other producing fields in the Norway sector of the North Sea and in the Norwegian Sea, as well as the Aasta Hansteen development. The operator is targeting first gas for Aasta Hansteen by late 2018.

*Exploration*
ConocoPhillips participated in four nonoperated exploration and appraisal wells in the Oseberg, Visund and Aasta Hansteen areas. Two wells in the Oseberg area were discoveries and were put on production; the others were discoveries currently undergoing evaluation. ConocoPhillips was awarded two new exploration licenses in early 2015, PL044C and PL782S with interests of 41.9 and 40.0 percent, respectively. Two more licenses were awarded in early 2016, PL845 and PL782SB, both with interests of 40.0 percent.

*Transportation*
We own a 35.1 percent interest in the Norpipe Oil Pipeline System, a 220-mile pipeline which carries crude oil from Ekofisk to a crude oil stabilization and natural gas liquids processing facility in Teesside, England. In November 2015, we sold our 1.9 percent interest in Norwegian Continental Shelf Gas Transportation (Gassled), which owns most of the Norwegian gas transportation infrastructure.

**United Kingdom**

| | | | 2015 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Britannia | 58.7% | ConocoPhillips | 4 | 92 | 19 |
| Britannia Satellites | 50.0–83.5* | ConocoPhillips | 10 | 55 | 19 |
| J-Area | 32.5–36.5 | ConocoPhillips | 15 | 87 | 30 |
| Southern North Sea | Various | Various | - | 58 | 10 |
| East Irish Sea | 100.0 | HRL | - | 29 | 5 |
| Other | Various | Various | 5 | 1 | 5 |
| Total United Kingdom | | | 34 | 322 | 88 |

** Does not include partner operated Alder project; first gas due 2016.*

Britannia is one of the largest natural gas and condensate fields in the North Sea. We assumed operatorship of Britannia in August 2015, following the acquisition of third party equity in Britannia Operator Limited, which is now wholly owned by ConocoPhillips. Condensate is delivered through the Forties Pipeline to an oil stabilization and processing plant near the Grangemouth Refinery in Scotland, while natural gas is transported through Britannia's line to St. Fergus, Scotland. The Britannia satellite fields, Callanish and Brodgar, produce via subsea manifolds and pipelines linked to the Britannia platform. Project startups for the Brodgar H3 susbsea tieback, and Enochdhu, a single well tie back to Callanish, were achieved in the first and second quarters of 2015, respectively. These projects increased Britannia's production in 2015 by 13.8 MBOED net. We are continuing work to hook up the Alder module to the Britannia facilities and anticipate delivery of first gas in 2016. Alder is a high-pressure, high-temperature gas condensate reservoir located in the U.K. Continental Shelf, 17 miles west of the Britannia facilities.

The J-Area consists of the Judy/Joanne, Jade and Jasmine fields, located in the U.K. Central North Sea. The Jasmine Field is a high-pressure, high-temperature gas condensate reservoir located approximately six miles west of the Judy Platform. The development includes a 24-slot wellhead platform with a bridge-linked accommodation and utilities platform, a six-mile, 16-inch multi-phase pipeline bundle, and a riser and processing platform bridge-linked to the existing Judy Platform.

We have various ownership interests in several producing gas fields in the Rotliegendes and Carboniferous areas of the Southern North Sea. Decommissioning activity in the Southern North Sea is ongoing, with final production from the Viking transportation system and associated satellites achieved in early 2016. Our interests in the East Irish Sea include the Millom, Dalton and Calder fields, which are operated on our behalf by a third party.

We own a 24 percent interest in the Clair Field, located in the Atlantic Margin. Clair Ridge is the second phase of development for the Clair Field and is comprised of a 36-slot drilling and production facility with a bridge-linked accommodation and utilities platform. The new facilities will tie into existing oil and gas export pipelines to the Shetland Islands. Initial production for Clair Ridge is targeted for 2018.

*Exploration*
During 2015, we participated in a nonoperated exploration/appraisal well in the Greater Clair area which was a discovery. The discovery is undergoing evaluations for future development. We also drilled one operated exploration well north of the Jasmine Field in the Central Graben which was a dry hole, and were awarded two new licenses in the East Irish Sea.

*Transportation*
We operate the Teesside oil and Theddlethorpe gas terminals in which we have 29.3 percent and 50 percent ownership interests, respectively. We also have a 100 percent ownership interest in the Rivers Gas Terminal, operated by a third party.

**Greenland**
*Exploration*
In 2015, we conducted field-based, metocean studies in Baffin Bay in Block 2011/11 of our operated Qamut license. Additionally, we participated in a 2-D seismic acquisition program and geological and geophysical studies as part of the work program obligation in the nonoperated Avinngaq license. In the fourth quarter of 2015, we initiated the process to assign our participating interest in the Avinngaq license. The process is pending Greenland government approval.

**Libya**

| | | | 2015 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Waha Concession | 16.3% | Waha Oil Co. | - | 1 | - |
| Total Libya | | | - | 1 | - |

The Waha Concession consists of multiple concessions and encompasses nearly 13 million gross acres in the Sirte Basin. Our production operations in Libya and related oil exports were interrupted in mid-2013, as a result of the shutdown of the Es Sider crude oil export terminal at the end of July 2013. The Es Sider Terminal briefly reopened in the third quarter of 2014 and production and liftings resumed temporarily; however, further disruptions occurred in December 2014, and production was shut in again. The Es Sider Terminal remained shut in throughout 2015. The 2016 operating and drilling activity is uncertain as a result of the ongoing civil unrest.

ASIA PACIFIC AND MIDDLE EAST

The Asia Pacific and Middle East segment has exploration and production operations in China, Indonesia, Malaysia and Australia; producing operations in Qatar and Timor-Leste; and exploration activities in Brunei. In 2015, operations in the Asia Pacific and Middle East segment contributed 13 percent of our worldwide liquids production and 33 percent of natural gas production.

**Australia and Timor Sea**

| | | | 2015 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Australia Pacific LNG | 37.5% | ConocoPhillips/ Origin Energy | - | 267 | 45 |
| Bayu-Undan | 56.9 | ConocoPhillips | 15 | 253 | 57 |
| Athena/Perseus | 50.0 | ExxonMobil | - | 35 | 6 |
| Total Australia and Timor Sea | | | 15 | 555 | 108 |

*Australia Pacific LNG*

Australia Pacific LNG Pty Ltd (APLNG), our joint venture with Origin Energy Limited and China Petrochemical Corporation (Sinopec), is focused on producing CBM from the Bowen and Surat basins in Queensland, Australia, and converting the CBM into LNG. Natural gas is sold to domestic customers, while LNG is exported. Origin operates APLNG's upstream production and pipeline system, and we operate the downstream LNG facility, located on Curtis Island near Gladstone, Queensland, as well as the LNG export sales business.

Two fully subscribed 4.5 million tonnes-per-year LNG trains have been sanctioned. Approximately 3,900 net wells are ultimately envisioned to supply both the domestic gas market and the LNG sales contracts. The wells will be supported by gathering systems, central gas processing and compression stations, water treatment facilities, and a new export pipeline connecting the gas fields to the LNG facilities. APLNG Train 1 achieved first LNG in the fourth quarter of 2015 and the first cargo sailed in January 2016. Train 1 LNG is being sold to Sinopec under a 20-year sales agreement for up to 4.3 million metric tonnes of LNG per year. Start-up of the second LNG train is expected to occur in the second half of 2016. The resulting LNG exports from Train 2 will commence shortly thereafter. Sinopec has agreed to purchase an additional 3.3 million metric tonnes of LNG per year through 2035, and Japan-based Kansai Electric Power Co., Inc. has agreed to purchase approximately 1 million metric tonnes of LNG per year for 20 years.

APLNG has an $8.5 billion project finance facility, of which $8.4 billion had been drawn from the facility at December 31, 2015. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility until the project achieves financial completion. For additional information, see Note 4—Variable Interest Entities (VIEs), Note 7—Investments, Loans and Long-Term Receivables, and Note 12—Guarantees, in the Notes to Consolidated Financial Statements.

*Bayu-Undan*

The Bayu-Undan gas condensate field is located in the Timor Sea Joint Petroleum Development Area between Timor-Leste and Australia. We also operate and own a 56.9 percent interest in the associated Darwin LNG Facility, located at Wickham Point, Darwin.

The Bayu-Undan natural gas recycle facility processes wet gas; separates, stores and offloads condensate, propane and butane; and re-injects dry gas back into the reservoir. In addition, a 310-mile natural gas pipeline connects the facility to the 3.5 million tonnes-per-year capacity Darwin LNG Facility. Produced natural gas is piped to the Darwin LNG Plant, where it is converted into LNG before being transported to international markets. In 2015, we sold 174 billion gross cubic feet of LNG primarily to utility customers in Japan.

The Bayu-Undan Phase Three Development consists of two standalone, subsea horizontal wells tied back to the existing drilling, production and processing platform. The first subsea, horizontal well commenced production in the first quarter of 2015. The well was tied back to the existing drilling, production, and processing platform. A second subsea, horizontal well was drilled, completed, then suspended due to insufficient deliverability to the platform. There are no plans to remediate nor re-drill the well in the near future. A continuation of Phase Three development is being evaluated, and is currently in the preliminary front-end engineering and design phase.

ConocoPhillips served a Notice of Arbitration on the Timor-Leste Minister of Finance in October 2012 for outstanding disputes related to a series of tax assessments. The arbitration hearing was conducted in June 2014. In January 2016, the Government of Timor-Leste and ConocoPhillips reached a settlement of several significant tax disputes. However, we await the Tribunal's decision with respect to certain unresolved matters. For additional information, see Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

*Athena/Perseus*
The Athena production license (WA-17-L) is located offshore Western Australia and contains part of the Perseus Field which straddles the boundary with WA-1-L, an adjoining license area. Natural gas is produced from these licenses.

*Greater Sunrise*
We have a 30 percent interest in the Greater Sunrise gas and condensate field located in the Timor Sea. In May 2013, the Timor-Leste Government referred a dispute with the Australian Government relating to the treaty on Certain Maritime Arrangements in the Timor Sea (CMATS) to international arbitration. The CMATS arbitration does not directly impact our underlying interests in Sunrise; however, we and the Sunrise co-venturers are unable to commit to further commercial and technical work activities due to the uncertainty created by the lack of government alignment. Accordingly, current activities are restricted to compliance and social investment, as well as maintaining relationships and development options for Sunrise.

*Exploration*

- *Conventional Exploration*
  We operate two exploration permits in the Browse Basin, offshore northwest Australia, in which we own a 40 percent interest in permits WA-315-P and WA-398-P, of the Greater Poseidon Area. Phase I of the Browse Basin drilling campaign in 2009/2010 resulted in three discoveries in the Greater Poseidon Area: Poseidon-1, Poseidon-2 and Kronos-1. Phase II of the drilling campaign resulted in five additional discoveries: Boreas-1, Zephyros-1, Proteus-1 SD2, Poseidon-North-1 and Pharos-1. All wells have been completed, plugged and abandoned.

  We operate two retention leases in the Bonaparte Basin, offshore northern Australia, where we own a 37.5 percent interest in leases NT/RL5 and NT/RL6, containing the Barossa and Caldita discoveries. Three appraisal wells have been drilled to further evaluate the Barossa Field's potential. The first two wells encountered hydrocarbons and the third was not commercially viable.

- *Unconventional Exploration*
  In 2015, regulatory approval was received to withdraw from the four exploration permits within the Canning Basin in Western Australia. Prior to withdrawal, we owned a 46 percent working interest in each of the four permits.

**Indonesia**

| | | | 2015 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| South Natuna Sea Block B | 40.0% | ConocoPhillips | 8 | 89 | 23 |
| South Sumatra | 45.0–54.0 | ConocoPhillips | 3 | 332 | 58 |
| Total Indonesia | | | 11 | 421 | 81 |

We operate four production sharing contracts (PSCs) in Indonesia: the offshore South Natuna Sea Block B and three onshore PSCs, the Corridor Block and South Jambi "B", both located in South Sumatra, and Kualakurun in Central Kalimantan. Currently there is production from two of these PSCs: the Corridor Block and South Natuna Sea Block B.

*South Natuna Sea Block B*
The offshore South Natuna Sea Block B PSC has 3 producing oil fields and 16 natural gas fields in various stages of development. Natural gas production is sold under international sales agreements to Malaysia and Singapore, and liquefied petroleum gas is sold locally for domestic consumption.

*South Sumatra*
The Corridor PSC consists of five oil fields and seven natural gas fields in various stages of development. Natural gas is supplied from the Grissik and Suban gas processing plants to the Duri steamflood in central Sumatra and to markets in Singapore, Batam and West Java. Production from the South Jambi "B" PSC has reached depletion and field development has been suspended.

*Exploration*
In 2015, we drilled and subsequently recorded dry hole expense for one exploration well in the Palangkaraya PSC. This PSC was relinquished in the third quarter of 2015. We are also in the process of relinquishing our 80 percent interest in the Warim Block PSC. We have a 60 percent working interest in the new Kualakurun PSC, located in Central Kalimantan, which was signed in May 2015. This block has an area of approximately 2 million gross acres.

*Transportation*
We are a 35 percent owner of a consortium company that has a 40 percent ownership in PT Transportasi Gas Indonesia, which owns and operates the Grissik to Duri and Grissik to Singapore natural gas pipelines.

**China**

| | | | 2015 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Penglai | 49.0% | CNOOC | 34 | 2 | 34 |
| Panyu | 24.5 | CNOOC | 11 | - | 11 |
| Total China | | | 45 | 2 | 45 |

The Penglai 19-3, 19-9 and 25-6 fields are located in Bohai Bay Block 11/05. Production from the Phase 1 development of the Penglai 19-3 Field began in 2002. Phase 2 included six additional wellhead platforms and an FPSO vessel, and was fully operational by 2009.

Currently, a project to add a new wellhead platform and up to 62 wells for the development of Penglai 19-9 is progressing per schedule, with first oil expected in 2017.

We sanctioned the Penglai 19-3/19-9 Phase 3 Project in December 2015. This project will consist of three new wellhead platforms and a central processing platform. First oil from Phase 3 is expected in 2018.

The Panyu development, located in Block 15/34 in the South China Sea, is comprised of three oil fields: Panyu 4-2, Panyu 5-1 and Panyu 11-6. The PSC for the block is scheduled to expire in September 2018, at which time we will relinquish all working interest in the block.

*Exploration*
In 2015, we participated in two successful appraisal wells in the Penglai fields, which will be used to support future development plans.

**Malaysia**

| | | | 2015 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Siakap North-Petai | 21.0% | Murphy | 4 | 2 | 4 |
| Gumusut | 29.0 | Shell | 25 | - | 25 |
| KBB | 30.0 | KPOC | - | 4 | 1 |
| Total Malaysia | | | 29 | 6 | 30 |

We own interests in four deepwater PSCs in Malaysia. Three are located off the eastern Malaysian state of Sabah: Block G, Block J and the Kebabangan Cluster (KBBC). Our fourth PSC, deepwater Block 3E, is located off the Malaysian state of Sarawak.

*Block G*
We have a 21 percent interest in the unitized Siakap North-Petai oil field, which began producing in the first quarter of 2014 and reached its estimated net annual peak production of 5 MBOED in 2015. Development of the Malikai oil field is underway with first production anticipated in 2017. We own a 35 percent interest in the Malikai and Pisagan discoveries.

*Block J*
First production for Gumusut occurred from an early production system in 2012. Production from a permanent, semi-submersible floating production vessel was achieved in October 2014, with estimated net annual peak production of 32 MBOED anticipated in 2016. Unitization of the Gumusut Field with Brunei was recorded in 2014 and reduced our ownership interest from 33 percent to an initial 29 percent. A final ownership split is expected to be agreed in 2016.

We own a 40 percent interest in the Limbayong discovery. The Limbayong-2 appraisal well, located approximately seven miles from Gumusut, was drilled in 2013 and resulted in an oil discovery. Development options are being evaluated.

*KBBC*
We own a 30 percent interest in the KBBC PSC. Development of the KBB gas field commenced in 2011, and first production was achieved in November 2014. Gas sales are currently constrained due to repairs on a third party pipeline. Estimated net annual peak production of 26 MBOED is expected in 2018. Kamunsu East is being evaluated for development options.

*Exploration*
We relinquished our 40 percent operating interest in SB-311, an exploration block encompassing 259,000 gross acres offshore Sabah, in December 2015. Both wells drilled in 2015 as part of our two-well commitment program were expensed as dry holes in the second and third quarters of 2015.

We own a 50 percent operating interest in deepwater Block 3E, which encompasses approximately 480,000 gross acres offshore Sarawak. Seismic processing was completed in 2015 and drilling is planned for 2016-2017.

**Bangladesh**
*Exploration*
In 2014, we relinquished our interest in two deepwater blocks in the Bay of Bengal, Blocks 10 and 11. In 2015, we also opted not to pursue our interest in three adjoining deepwater blocks and exited operations in Bangladesh.

**Brunei**
*Exploration*
We have a 6.25 percent working interest in the deepwater Block CA-2 PSC, which has an exploration period through December 2018. Exploration has been ongoing since September 2011, with natural gas discovered at the Kelidang NE-1 and Keratau-1 wells in 2013 and at the Keratau SW-1 well in 2015. Evaluation of the results is ongoing.

**Myanmar**
*Exploration*
In 2014, we were awarded deepwater Block AD-10 in the 2013 Myanmar offshore oil and gas bidding round. We signed the PSC in the second quarter of 2015, and in the third quarter we initiated the process to assign our participating interest to the operator, pending Myanmar government approval.

**Qatar**

| | | | 2015 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| QG3 | 30.0% | Qatargas Operating Company Limited | 21 | 371 | 83 |
| Total Qatar | | | 21 | 371 | 83 |

QG3 is an integrated development jointly owned by Qatar Petroleum (68.5 percent), ConocoPhillips (30 percent) and Mitsui & Co., Ltd. (1.5 percent). QG3 consists of upstream natural gas production facilities, which produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar's North Field over a 25 year life, in addition to a 7.8 million gross tonnes-per-year LNG facility. LNG is shipped in leased LNG carriers destined for sale globally.

QG3 executed the development of the onshore and offshore assets as a single integrated development with Qatargas 4 (QG4), a joint venture between Qatar Petroleum and Royal Dutch Shell plc. This included the joint development of offshore facilities situated in a common offshore block in the North Field, as well as the construction of two identical LNG process trains and associated gas treating facilities for both the QG3 and QG4 joint ventures. Production from the LNG trains and associated facilities is combined and shared.

OTHER INTERNATIONAL

The Other International segment includes exploration activities in Colombia, Angola and Senegal. In the fourth quarter of 2015, we exited our operations in Russia. During 2015, operations in Other International contributed less than 1 percent of our worldwide liquids production.

**Russia**

| | | | 2015 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Polar Lights | 50.0% | Polar Lights Co. | 4 | - | 4 |
| Total Russia | | | 4 | - | 4 |

<u>Polar Lights</u>
In the fourth quarter of 2015, we completed the sale of our 50 percent interest in the Polar Lights Company, an entity which has developed several fields in the Timan-Pechora Basin in northern Russia.

**Angola**
<u>Exploration</u>
We have a 50 percent operating interest in Block 36 and a 30 percent operating interest in Block 37, both of which are located in Angola's subsalt play trend. The two blocks total approximately 2.5 million gross acres and each block was awarded with a two-well work program commitment. We secured a rig for a four-well commitment program and commenced drilling in the second quarter of 2014. In November 2014, we plugged and abandoned the Kamoxi-1 exploration well, located in Block 36 offshore Angola, as a dry hole. We also subsequently plugged and abandoned the Omosi-1 and Vali-1 wells as dry holes in adjacent Block 37 in the first and second quarters of 2015, respectively, and recorded an after-tax impairment of $75 million associated with our Angola Block 37 leasehold in the second quarter of 2015. In the fourth quarter of 2015, we recorded $335 million in after-tax charges for the impairment, dry hole costs and future potential obligations associated with our Angola Block 36 leasehold. The Athena drilling rig, secured for our four-well commitment program, was mobilized to Senegal in October.

**Senegal**
<u>Exploration</u>
We have a 35 percent working interest in three exploration blocks offshore Senegal. In October 2014, we discovered a working petroleum system at the FAN-1 exploration well. In addition, in November 2014 we confirmed oil was discovered in the SNE-1 well, the second of the two-well program. We spud the SNE-2 and SNE-3 appraisal wells in the fourth quarter of 2015. We have the option to become operator of the project if it advances to development.

**Azerbaijan**
<u>Transportation</u>
The Baku-Tbilisi-Ceyhan (BTC) Pipeline transports crude oil from the Caspian Region through Azerbaijan, Georgia and Turkey for tanker loadings at the port of Ceyhan. In the fourth quarter of 2015, we finalized the sale of our 2.5 percent interest in BTC.

**Poland**
<u>Exploration</u>
In the second quarter of 2015, we decided not to conduct further activity on our three Baltic Basin concessions, which encompassed approximately 500,000 gross acres. As a result, we recorded an after-tax impairment of $32 million, net of other deductions.

**Colombia**
*Unconventional Exploration*
We have an 80 percent operated interest in the Middle Magdalena Basin block VMM-3. The block extends over 66,649 net acres and contains the Picoplata-1, which completed drilling in 2015. Continued evaluation and testing of the well is planned in 2016.

We hold 70 percent nonoperated interests in the deep rights in the Santa Isabel Block in the Middle Magdalena Basin, which covers approximately 71,000 net acres. We also hold a 30 percent nonoperated interest in the VMM27 and VMM28 blocks, in the Middle Magdalena Basin, which are currently in the process of being relinquished.

**Chile**
*Exploration*
In the fourth quarter of 2015, we received approval from the Chilean government to become a 5 percent interest holder in the Coiron Block. Empresa Nacional del Petroleo holds the remaining 95 percent interest and is the operator of the block.

**Venezuela**
In October 2014, we filed for arbitration under the rules of the International Chamber of Commerce (ICC) against Petroleos de Venezuela (PDVSA), the Venezuela state oil company, for contractual compensation related to the Petrozuata and Hamaca heavy crude oil projects. The ICC arbitration is a separate and independent legal action from the investment treaty arbitration against the government of Venezuela, which is currently proceeding before an arbitral tribunal under the World Bank's International Centre for Settlement for Investment Disputes (ICSID). The ICSID Tribunal is determining the damages owed to ConocoPhillips as a result of Venezuela's unlawful expropriation of ConocoPhillips' significant oil investments in the Petrozuata and Hamaca heavy crude oil projects and the offshore Corocoro development project in June 2007. For additional information, see Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

**Ecuador**
In December 2012, an ICSID Tribunal issued a decision on liability in favor of Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, finding that Ecuador's seizure of Blocks 7 and 21 was an unlawful expropriation in violation of the Ecuador-U.S. Bilateral Investment Treaty. An additional arbitration phase to determine the damages owed to ConocoPhillips for Ecuador's actions and to address Ecuador's counterclaims followed the decision on liability and we are now waiting for the Tribunal's award. For additional information, see Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

**Discontinued Operations**

See Note 3—Discontinued Operations, in the Notes to Consolidated Financial Statements, for information regarding our discontinued operations.

OTHER

**Marketing Activities**
Our Commercial organization manages our worldwide commodity portfolio, which mainly includes natural gas, crude oil, bitumen, natural gas liquids and LNG. Marketing activities are performed through offices in the United States, Canada, Europe and Asia. In marketing our production, we attempt to minimize flow disruptions, maximize realized prices and manage credit-risk exposure. Commodity sales are generally made at prevailing market prices at the time of sale. We also purchase and sell third-party volumes to better position the company to satisfy customer demand while fully utilizing transportation and storage capacity.

*Natural Gas*
Our natural gas production, along with third-party purchased gas, is primarily marketed in the United States, Canada, Europe and Asia. Our natural gas is sold to a diverse client portfolio which includes local distribution companies; gas and power utilities; large industrials; independent, integrated or state-owned oil and gas companies; as well as marketing companies. To reduce our market exposure and credit risk, we also transport natural gas via firm and interruptible transportation agreements to major market hubs.

*Crude Oil, Bitumen and Natural Gas Liquids*
Our crude oil, bitumen and natural gas liquids revenues are derived from production in the United States, Canada, Australia, Asia, Africa and Europe. These commodities are primarily sold under contracts with prices based on market indices, adjusted for location, quality and transportation.

*LNG*
LNG marketing efforts are focused on equity LNG production facilities located in Alaska, Australia, and Qatar. LNG is primarily sold under long-term contracts with prices based on market indices.

**Energy Partnerships**
*Marine Well Containment Company*
We are a founding member of the Marine Well Containment Company (MWCC), a non-profit organization formed in 2010, which provides well containment equipment and technology in the deepwater U.S. Gulf of Mexico. In January 2015, MWCC announced acceptance of its expanded containment system (ECS). The ECS complements the capabilities and capacities put into place with its interim containment system, which the industry has been relying on since 2011. Equipment from both systems has been combined to form MWCC's containment system, which meets the U.S. Bureau of Safety and Environmental Enforcement requirements for a subsea well containment system that can respond to a deepwater well control incident in the U.S. Gulf of Mexico.

*Subsea Well Response Project*
In 2011, we, along with several leading oil and gas companies, launched the Subsea Well Response Project (SWRP), a non-profit organization based in Stavanger, Norway, which was created to enhance the industry's capability to respond to international subsea well control incidents. Through collaboration with Oil Spill Response Limited, a non-profit organization in the United Kingdom, subsea well intervention equipment is available for the industry to use in the event of a subsea well incident. This complements the work being undertaken in the United States by MWCC.

*Oil Spill Response Removal Organizations (OSROs)*
We maintain memberships in several OSROs across the globe as a key element of our preparedness program in addition to internal response resources. Many of the OSROs are not-for-profit cooperatives owned by the member companies wherein we may actively participate as a member of the board of directors, steering committee, work group or other supporting role. Globally, our primary OSRO is Oil Spill Response Ltd. based in the U.K., with facilities in several other countries and the ability to respond anywhere in the world. In North America, our primary OSROs include the Marine Spill Response Corporation for the continental U.S. and Alaska Clean Seas and Ship Escort/Response Vessel System for the Alaska North Slope and Prince

William Sound, respectively. We are also a member of the Cook Inlet Spill Prevention and Response, Inc. Internationally, we maintain memberships in various regional OSROs including the Norwegian Clean Seas Association for Operating Companies, Australian Marine Oil Spill Center and Petroleum Industry of Malaysia Mutual Aid Group.

**Technology**

Our Technology organization has several technology programs, which focus on areas to support our business growth plans: developing unconventional reservoirs, producing oil sands and heavy oil economically with fewer emissions, improving the economic efficiency of our LNG and other gas solutions technologies, increasing recoveries from our legacy fields, and implementing sustainability measures.

Our Optimized Cascade® LNG liquefaction technology business continues to be successful with the demand for new LNG plants. The technology has been licensed for use in 25 LNG trains around the world, with feasibility studies ongoing for additional trains.

## RESERVES

We have not filed any information with any other federal authority or agency with respect to our estimated total proved reserves at December 31, 2015. No difference exists between our estimated total proved reserves for year-end 2014 and year-end 2013, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2015.

## DELIVERY COMMITMENTS

We sell crude oil and natural gas from our producing operations under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Our Commercial organization also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be the spot market or a combination of our reserves and the spot market. Worldwide, we are contractually committed to deliver approximately 2.5 trillion cubic feet of natural gas, including approximately 430 billion cubic feet related to the noncontrolling interests of consolidated subsidiaries, and 230 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2028. We expect to fulfill the majority of these delivery commitments with proved developed reserves. In addition, we anticipate using proved undeveloped reserves and spot market purchases to fulfill any remaining commitments. See the disclosure on "Proved Undeveloped Reserves" in the "Oil and Gas Operations" section following the Notes to Consolidated Financial Statements, for information on the development of proved undeveloped reserves.

## COMPETITION

We compete with private, public and state-owned companies in all facets of the E&P business. Some of our competitors are larger and have greater resources. Each of our segments is highly competitive, with no single competitor, or small group of competitors, dominating.

We compete with numerous other companies in the industry, including state-owned companies, to locate and obtain new sources of supply and to produce oil, bitumen, natural gas liquids and natural gas in an efficient, cost-effective manner. Based on statistics published in the September 7, 2015, issue of the *Oil and Gas Journal*, we were the third-largest U.S.-based oil and gas company in worldwide liquids and natural gas production and reserves in 2014. We deliver our production into the worldwide commodity markets. Principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; economic analysis in connection with portfolio management; and safely operating oil and gas producing properties.

## GENERAL

At the end of 2015, we held a total of 1,012 active patents in 58 countries worldwide, including 387 active U.S. patents. During 2015, we received 46 patents in the United States and 85 foreign patents. Our products and processes generated licensing revenues of $271 million in 2015. The overall profitability of any business segment is not dependent on any single patent, trademark, license, franchise or concession.

Company-sponsored research and development activities charged against earnings were $222 million, $263 million and $258 million in 2015, 2014 and 2013, respectively.

*Health, Safety and Environment*

Our Health, Safety and Environment (HSE) organization provides tools and support to our business units and staff groups to help them ensure world class health, safety and environmental performance. The framework through which we safely manage our operations, the HSE Management System Standard, emphasizes process safety, risk management, emergency preparedness and environmental performance, with an intense focus on process and occupational safety. In support of the goal of zero incidents, HSE milestones and criteria are established annually to drive strong safety performance. Progress toward these milestones and criteria are measured and reported. HSE audits are conducted on business functions periodically, and improvement actions are established and tracked to completion. We also have detailed processes in place to address sustainable development in our economic, environmental and social performance. Our processes, related tools and requirements focus on water, biodiversity and climate change, as well as social and stakeholder issues.

The environmental information contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 62 through 66 under the captions "Environmental" and "Climate Change" is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2015 and those expected for 2016 and 2017.

**Website Access to SEC Reports**

Our internet website address is *www.conocophillips.com*. Information contained on our internet website is not part of this report on Form 10-K.

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on our website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the U.S. Securities and Exchange Commission (SEC). Alternatively, you may access these reports at the SEC's website at *www.sec.gov*.

## Item 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this Annual Report on Form 10-K. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

***Our operating results, our future rate of growth and the carrying value of our assets are exposed to the effects of changing commodity prices.***

Prices for crude oil, bitumen, natural gas, natural gas liquids and LNG can fluctuate widely. Globally, prices for crude oil, bitumen, natural gas, natural gas liquids and LNG have recently experienced significant declines from their historic levels during 2013 and 2014, with continued global production increases that have outpaced demand growth, leading to a large observed rise in global inventory. Prices for Brent crude oil, WTI crude oil, Henry Hub natural gas and natural gas liquids in the fourth quarter of 2015 have all declined more than 40 percent when compared with prices in the fourth quarter of 2014, and there are no indications the price declines will reverse themselves in the immediate future.

Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil, bitumen, natural gas, natural gas liquids and LNG. The factors influencing these prices are beyond our control. Lower crude oil, bitumen, natural gas, natural gas liquids and LNG prices may have a material adverse effect on our revenues, operating income, cash flows and liquidity and on the amount of dividends we elect to declare and pay on our common stock. Lower prices may also limit the amount of reserves we can produce economically, adversely affecting our ability to maintain our reserve replacement ratio and accelerating the reduction in our existing reserve levels as we continue production from upstream fields.

Significant reductions in crude oil, bitumen, natural gas, natural gas liquids and LNG prices could also require us to reduce our capital expenditures or impair the carrying value of our assets. During 2015, we recognized several impairments, which are described in Note 9—Impairments, in the Notes to Consolidated Financial Statements. If commodity prices remain low relative to their historic levels, and as we continue to optimize our investments and exercise capital flexibility, it is reasonably likely we will incur future impairments to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method and unproved properties. Although it is not reasonably practicable to quantify the impact of any future impairments at this time, our results of operations could be adversely affected as a result.

***Our ability to declare and pay dividends is subject to certain considerations.***

Dividends are authorized and determined by our Board of Directors in its sole discretion and depend upon a number of factors, including:

- Cash available for distribution.
- Our results of operations and anticipated future results of operations.
- Our financial condition, especially in relation to the anticipated future capital needs of our properties.
- The level of reserves we establish for future capital expenditures.
- The level of distributions paid by comparable companies.
- Our operating expenses.
- Other factors our Board of Directors deems relevant.

We expect to continue to pay quarterly distributions to our stockholders; however, we bear all expenses incurred by our operations, and our funds generated by operations, after deducting these expenses, may not be sufficient to cover desired levels of distributions to our stockholders. Any downward revision in our distribution could have a material adverse effect on the market price of our common stock.

***We may need additional capital in the future, and it may not be available on acceptable terms.***

We have historically relied primarily upon cash generated by our operations to fund our operations and strategy, however we have also relied from time to time on access to the debt and equity capital markets for funding. There can be no assurance that additional debt or equity financing will be available in the future on acceptable terms, or at all. Our ability to obtain additional financing will be subject to a number of factors, including market conditions, our operating performance, investor sentiment and our ability to incur additional debt in compliance with agreements governing our then-outstanding debt. If we are unable to generate sufficient funds from operations or raise additional capital, our growth could be impeded.

In addition, we are regularly evaluated by the major rating agencies based on a number of factors, including our financial strength and conditions affecting the oil and gas industry generally. Due to the significant recent decline in prices for crude oil, bitumen, natural gas, natural gas liquids and LNG, and the expectation that these prices could remain depressed in the near future, the major ratings agencies have indicated they will be conducting a review of the oil and gas industry and the debt ratings for some companies operating in the industry may be downgraded. The results of these actions, including any downgrade in our credit rating, could increase the cost associated with any additional indebtedness we incur.

***Our business may be adversely affected by deterioration in the credit quality of, or defaults under our contracts with, third parties with whom we do business.***

The operation of our business requires us to engage in transactions with numerous counterparties operating in a variety of industries, including other companies operating in the oil and gas industry. These counterparties may default on their obligations to us as a result of operational failures or a lack of liquidity, or for other reasons, including bankruptcy. Market speculation about the credit quality of these counterparties, or their ability to continue performing on their existing obligations, may also exacerbate any operational difficulties or liquidity issues they are experiencing, particularly as it relates to other companies in the oil and gas industry as a result of the recent significant declines in commodity prices. Any default by any of our counterparties may result in our inability to perform obligations under agreements we have made with third parties or may otherwise adversely affect our business or results of operations. In addition, our rights against any of our counterparties as a result of a default may not be adequate to compensate us for the resulting harm caused or may not be enforceable at all in some circumstances.

***Unless we successfully add to our existing proved reserves, our future crude oil, bitumen, natural gas and natural gas liquids production will decline, resulting in an adverse impact to our business.***

The rate of production from upstream fields generally declines as reserves are depleted. Except to the extent that we conduct successful exploration and development activities, or, through engineering studies, optimize production performance or identify additional or secondary recovery reserves, our proved reserves will decline materially as we produce crude oil, bitumen, natural gas and natural gas liquids. Accordingly, to the extent we are unsuccessful in replacing the crude oil, bitumen, natural gas and natural gas liquids we produce with good prospects for future production, our business will experience reduced cash flows and results of operations. Any cash conservation efforts we may undertake as a result of commodity price declines may further limit our ability to replace depleted reserves.

***Any material change in the factors and assumptions underlying our estimates of crude oil, bitumen, natural gas and natural gas liquids reserves could impair the quantity and value of those reserves.***

Our proved reserve information included in this annual report has been derived from engineering estimates prepared by our personnel. Reserve estimation is a process that involves estimating volumes to be recovered from underground accumulations of crude oil, bitumen, natural gas and natural gas liquids that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of reserves and future net cash flows based on the same available data. Any significant future price changes could have a material effect on the quantity and present value of our proved reserves. Any material changes in the factors and assumptions underlying our estimates of these items could result in a material negative impact to the volume of reserves reported or could cause us to incur impairment expenses on property associated with the production of those reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation. In addition to changes in the quantity and value of our proved reserves, the amount of crude oil, bitumen, natural gas and natural gas liquids that can be obtained from any proved reserve may ultimately be different from those estimated prior to extraction.

***We expect to continue to incur substantial capital expenditures and operating costs as a result of our compliance with existing and future environmental laws and regulations. Likewise, future environmental laws and regulations, such as limitations on greenhouse gas emissions, may impact or limit our current business plans and reduce demand for our products.***

Our businesses are subject to numerous laws and regulations relating to the protection of the environment. These laws and regulations continue to increase in both number and complexity and affect our operations with respect to, among other things:

- The discharge of pollutants into the environment.
- Emissions into the atmosphere, such as nitrogen oxides, sulfur dioxide, mercury and greenhouse gas emissions.
- Carbon taxes.
- The handling, use, storage, transportation, disposal and cleanup of hazardous materials and hazardous and nonhazardous wastes.
- The dismantlement, abandonment and restoration of our properties and facilities at the end of their useful lives.
- Exploration and production activities in certain areas, such as offshore environments, arctic fields, oil sands reservoirs and tight oil plays.

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our business, financial condition, results of operations and cash flows in future periods could be materially adversely affected.

Although our business operations are designed and operated to accommodate expected climatic conditions, to the extent there are significant changes in the Earth's climate, such as more severe or frequent weather conditions in the markets we serve or the areas where our assets reside, we could incur increased expenses, our operations could be materially impacted, and demand for our products could fall. Demand for our products may also be adversely affected by conservation plans and efforts undertaken in response to global climate change, including plans developed in connection with the recent Paris climate conference in December 2015. Many governments also provide, or may in the future provide, tax advantages and other subsidies to support the use and development of alternative energy technologies. Our operations and the demand for our products could be materially impacted by the development and adoption of these technologies.

***Domestic and worldwide political and economic developments could damage our operations and materially reduce our profitability and cash flows.***

Actions of the U.S., state, local and foreign governments, through tax and other legislation, executive order and commercial restrictions, could reduce our operating profitability both in the United States and abroad. In certain locations, governments have imposed or proposed restrictions on our operations; special taxes or tax assessments; and payment transparency regulations that could require us to disclose competitively sensitive information or might cause us to violate non-disclosure laws of other countries. U.S. federal, state and local legislative and regulatory agencies' initiatives regarding the hydraulic fracturing process could result in operating restrictions or delays in the completion of our oil and gas wells.

The U.S. government can also prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries. Actions by host governments have affected operations significantly in the past, such as the expropriation of our oil assets by the Venezuelan government, and may continue to do so in the future. Changes in domestic and international regulations may affect our ability to obtain or maintain permits, including those necessary for drilling and development of wells or for construction of LNG terminals or regasification facilities in various locations.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 54 percent of our hydrocarbon production from continuing operations was derived from production outside the United States in 2015, and 61 percent of our proved reserves, as of December 31, 2015, was located outside the United States. We are subject to risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas, bitumen, natural gas liquids or LNG pricing and taxation, other political, economic or diplomatic developments, changing political conditions and international monetary fluctuations. In particular, some countries where we operate lack well-developed legal systems or have not adopted clear legal and regulatory frameworks for oil and gas exploration and production. This lack of legal certainty exposes our operations to increased risks, including increased difficulty in enforcing our agreements in those jurisdictions and increased risks of adverse actions by local government authorities, such as expropriations.

***Changes in governmental regulations may impose price controls and limitations on production of crude oil, bitumen, natural gas and natural gas liquids.***

Our operations are subject to extensive governmental regulations. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of crude oil, bitumen, natural gas and natural gas liquids wells below actual production capacity. Because legal requirements are frequently changed and subject to interpretation, we cannot predict the effect of these requirements.

***Our investments in joint ventures decrease our ability to manage risk.***

We conduct many of our operations through joint ventures in which we may share control with our joint venture partners. There is a risk our joint venture participants may at any time have economic, business or legal interests or goals that are inconsistent with those of the joint venture or us, or our joint venture partners may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone. Failure by us, or an entity in which we have a joint venture interest, to adequately manage the risks associated with any acquisitions or joint ventures could have a material adverse effect on the financial condition or results of operations of our joint ventures and, in turn, our business and operations.

***We do not insure against all potential losses; therefore, we could be harmed by unexpected liabilities and increased costs.***

We maintain insurance against many, but not all, potential losses or liabilities arising from operating risks. As such, our insurance coverage may not be sufficient to fully cover us against potential losses arising from such risks. Uninsured losses and liabilities arising from operating risks could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

***Our operations present hazards and risks that require significant and continuous oversight.***

The scope and nature of our operations present a variety of significant hazards and risks, including operational hazards and risks such as explosions, fires, crude oil spills, severe weather, geological events, labor disputes, terrorist attacks, sabotage, civil unrest or cyber attacks. Our operations may also be adversely affected by unavailability, interruptions or accidents involving services or infrastructure required to develop, produce, process or transport our production, such as contract labor, drilling rigs, pipelines, railcars, tankers, barges or other infrastructure. Our operations are subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. Activities in deepwater areas may pose incrementally greater risks because of complex subsurface conditions such as higher reservoir pressures, water depths and metocean conditions. All such hazards could result in loss of human life, significant property and equipment damage, environmental pollution, impairment of operations, substantial losses to us and damage to our reputation. Further, our business and operations may be disrupted if we do not respond, or are perceived not to respond, in an appropriate manner to any of these hazards and risks or any other major crisis or if we are unable to efficiently restore or replace affected operational components and capacity.

Our technologies, systems and networks may be subject to cybersecurity breaches. Although we have experienced occasional, actual or attempted breaches of our cybersecurity, none of these breaches has had a material effect on our business, operations or reputation. If our systems for protecting against cybersecurity risks prove to be insufficient, we could be adversely affected by having our business systems compromised, our proprietary information altered, lost or stolen, or our business operations disrupted. As cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information systems and related infrastructure security vulnerabilities.

## Item 1B. UNRESOLVED STAFF COMMENTS

None.

## Item 3. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the fourth quarter of 2015, as well as matters previously reported in our 2014 Form 10-K and our first-, second- and third-quarter 2015 Form 10-Qs that were not resolved prior to the fourth quarter of 2015. Material developments to the previously reported matters have been included in the descriptions below. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings were to be decided adversely to ConocoPhillips, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to SEC regulations.

On April 30, 2012, the separation of our downstream business was completed, creating two independent energy companies: ConocoPhillips and Phillips 66. In connection with the separation, we entered into an Indemnification and Release Agreement, which provides for cross-indemnities between Phillips 66 and us and established procedures for handling claims subject to indemnification and related matters, such as legal proceedings. We have included matters where we remain a party to a proceeding relating to Phillips 66, in accordance with SEC regulations. We do not expect any of those matters to result in a net claim against us.

*Matters Previously Reported—Phillips 66*
In October 2007, ConocoPhillips received a Complaint from the U.S. Environmental Protection Agency (EPA) alleging violations of the Clean Water Act related to a 2006 oil spill at the Phillips 66 Bayway Refinery and proposing a penalty of $156,000.

On May 19, 2010, the Phillips 66 Lake Charles Refinery received a Consolidated Compliance Order and Notice of Potential Penalty from the Louisiana Department of Environmental Quality (LDEQ) alleging various violations of applicable air emission regulations, as well as certain provisions of the consent decree in Civil Action No. H-01-4430. In July 2014, Phillips 66 resolved the consent decree issues and in January 2016, an agreement was reached with LDEQ to resolve the remaining allegations.

On October 15, 2012, the Bay Area Air Quality Management District (Bay Area AQMD) issued a $313,000 demand to settle 13 other Notice of Violation (NOV) issued in 2010 and 2011 with respect to alleged violations of regulatory and/or permit requirements at the Phillips 66 Rodeo Refinery.

In May 2012, the Illinois Attorney General's office filed and notified ConocoPhillips of a complaint with respect to operations at the Phillips 66 WRB Wood River Refinery alleging violations of the Illinois groundwater standards and a third-party's hazardous waste permit. The complaint seeks as relief remediation of area groundwater; compliance with the hazardous waste permit; enhanced pipeline and tank integrity measures; additional spill reporting; and yet-to-be specified amounts for fines and penalties.

On July 7, 2014, Phillips 66 received an NOV from the U.S. EPA alleging various flaring-related violations between 2009 and 2013 at the Phillips 66 Wood River Refinery. ConocoPhillips is not a named party in the NOV and we will therefore no longer report this matter.

On July 8, 2014, the Bay Area AQMD issued a $175,000 demand to settle 18 NOVs issued in 2010 with respect to alleged violations of regulatory and/or permit requirements at the Phillips 66 Rodeo Refinery.

On July 8, 2014, the Bay Area AQMD issued a $259,000 demand to settle 20 NOVs issued in 2011 with respect to alleged violations of regulatory and/or permit requirements at the Phillips 66 Rodeo Refinery.

## Item 4. MINE SAFETY DISCLOSURES

Not applicable.

**EXECUTIVE OFFICERS OF THE REGISTRANT**

| Name | Position Held | Age* |
|---|---|---|
| Janet L. Carrig | Senior Vice President, Legal, General Counsel and Corporate Secretary | 58 |
| Ellen R. DeSanctis | Vice President, Investor Relations and Communications | 59 |
| Matt J. Fox | Executive Vice President, Exploration and Production | 55 |
| Alan J. Hirshberg | Executive Vice President, Technology and Projects | 54 |
| Ryan M. Lance | Chairman of the Board of Directors and Chief Executive Officer | 53 |
| Andrew D. Lundquist | Senior Vice President, Government Affairs | 55 |
| James D. McMorran | Vice President, Human Resources, Real Estate and Facilities Services | 58 |
| Glenda M. Schwarz | Vice President and Controller | 50 |
| Jeff W. Sheets | Executive Vice President, Finance and Chief Financial Officer | 58 |
| Don E. Wallette, Jr. | Executive Vice President, Commercial, Business Development and Corporate Planning | 57 |

**On February 15, 2016.*

There are no family relationships among any of the officers named above. Each officer of the company is elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and thereafter as appropriate. Each officer of the company holds office from the date of election until the first meeting of the directors held after the next Annual Meeting of Stockholders or until a successor is elected. The date of the next annual meeting is May 10, 2016. Set forth below is information about the executive officers.

**Janet L. Carrig** was appointed Senior Vice President, Legal, General Counsel and Corporate Secretary in 2007.

**Ellen R. DeSanctis** was appointed Vice President, Investor Relations and Communications in May 2012. She was previously employed by Petrohawk Energy Corp. and served as Senior Vice President, Corporate Communications since 2010. Prior to that she was employed by Rosetta Resources Inc. and served as Executive Vice President of Strategy and Development from 2008 to 2010.

**Matt J. Fox** was appointed Executive Vice President, Exploration and Production in May 2012. Prior to that, he was employed by Nexen, Inc. and served as Executive Vice President, International since 2010. He was previously employed by ConocoPhillips and served as President, ConocoPhillips Canada from 2009 to 2010.

**Alan J. Hirshberg** was appointed Executive Vice President, Technology and Projects in May 2012. Prior to that, he served as Senior Vice President, Planning and Strategy since 2010.

**Ryan M. Lance** was appointed Chairman of the Board of Directors and Chief Executive Officer in May 2012, having previously served as Senior Vice President, Exploration and Production—International since May 2009.

**Andrew D. Lundquist** was appointed Senior Vice President, Government Affairs in 2013. Prior to that, he served as managing partner of BlueWater Strategies LLC, since 2002.

**James D. McMorran** was appointed Vice President, Human Resources, Real Estate and Facilities Services in August 2015. Prior to that, he served as Manager, Compensation and Benefits, since 2004.

**Glenda M. Schwarz** was appointed Vice President and Controller in 2009.

**Jeff W. Sheets** was appointed Executive Vice President, Finance and Chief Financial Officer in May 2012, having previously served as Senior Vice President, Finance and Chief Financial Officer since 2010.

**Don E. Wallette, Jr.** was appointed Executive Vice President, Commercial, Business Development and Corporate Planning in May 2012. Prior to that, he served as President, Asia Pacific since 2010 and President, Russia/Caspian from 2006 to 2010.

On February 16, 2016, Jeff W. Sheets announced his decision to retire as Executive Vice President, Finance and Chief Financial Officer. Mr. Sheets will remain in his position as Executive Vice President, Finance and Chief Financial Officer until April 1, 2016, and following that will remain an employee through May 31, 2016, to provide support during the transition of his responsibilities.

In connection with Mr. Sheets' retirement, at a meeting held on February 16 and 17, 2016, the Board of Directors approved the following changes to our executive leadership team to become effective April 1, 2016:

- Don E. Wallette, Jr. will become Executive Vice President, Finance, Commercial and Chief Financial Officer.

- Al J. Hirshberg will become Executive Vice President, Production, Drilling and Projects.

- Matt Fox will become Executive Vice President, Strategy, Exploration and Technology.

## PART II

### Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

**Quarterly Common Stock Prices and Cash Dividends Per Share**

ConocoPhillips' common stock is traded on the New York Stock Exchange, under the symbol "COP."

| | | Stock Price | | |
|---|---|---|---|---|
| | | High | Low | Dividends |
| **2015** | | | | |
| First | **$** | **70.11** | **60.57** | **0.73** |
| Second | | **69.72** | **60.86** | **0.73** |
| Third | | **61.51** | **41.10** | **0.74** |
| Fourth | | **57.24** | **44.56** | **0.74** |
| 2014 | | | | |
| First | $ | 70.99 | 62.74 | 0.69 |
| Second | | 86.43 | 69.33 | 0.69 |
| Third | | 87.09 | 75.92 | 0.73 |
| Fourth | | 76.52 | 60.84 | 0.73 |

| | | |
|---|---|---|
| Closing Stock Price at December 31, 2015 | $ | 46.69 |
| Closing Stock Price at January 31, 2016 | $ | 39.08 |
| Number of Stockholders of Record at January 31, 2016* | | 52,394 |

**In determining the number of stockholders, we consider clearing agencies and security position listings as one stockholder for each agency listing.*

The declaration of dividends is subject to the discretion of our Board of Directors, and may be affected by various factors, including our future earnings, financial condition, capital requirements, levels of indebtedness, credit ratings and other considerations our Board of Directors deems relevant. Our Board of Directors has adopted a quarterly dividend declaration policy providing that the declaration of any dividends will be determined quarterly by the Board of Directors taking into account such factors as our business model, prevailing business conditions and our financial results and capital requirements, without a predetermined annual net income payout ratio.

On February 4, 2016, we announced that our Board of Directors approved a reduction in the quarterly dividend to $0.25 per share, compared with the previous quarterly dividend of $0.74 per share. The dividend is payable on March 1, 2016 to stockholders of record at the close of business on February 16, 2016.

**Issuer Purchases of Equity Securities**

During 2015, there were no active share repurchase programs and no repurchases of common stock from employees in connection with the company's broad-based employee incentive programs.

## Item 6. SELECTED FINANCIAL DATA

| | Millions of Dollars Except Per Share Amounts | | | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | 2013 | 2012 | 2011 |
| Sales and other operating revenues | $ **29,564** | 52,524 | 54,413 | 57,967 | 64,196 |
| Income (loss) from continuing operations | **(4,371)** | 5,807 | 8,037 | 7,481 | 7,188 |
| Per common share | | | | | |
| Basic | **(3.58)** | 4.63 | 6.47 | 5.95 | 5.18 |
| Diluted | **(3.58)** | 4.60 | 6.43 | 5.91 | 5.14 |
| Income from discontinued operations | **-** | 1,131 | 1,178 | 1,017 | 5,314 |
| Net income (loss) | **(4,371)** | 6,938 | 9,215 | 8,498 | 12,502 |
| Net income (loss) attributable to ConocoPhillips | **(4,428)** | 6,869 | 9,156 | 8,428 | 12,436 |
| Per common share | | | | | |
| Basic | **(3.58)** | 5.54 | 7.43 | 6.77 | 9.04 |
| Diluted | **(3.58)** | 5.51 | 7.38 | 6.72 | 8.97 |
| Total assets | **97,484** | 116,539 | 118,057 | 117,144 | 153,230 |
| Long-term debt | **23,453** | 22,383 | 21,073 | 20,770 | 21,610 |
| Joint venture acquisition obligation—long-term | **-** | - | - | 2,810 | 3,582 |
| Cash dividends declared per common share | **2.94** | 2.84 | 2.70 | 2.64 | 2.64 |

Net income (loss) and Net income (loss) attributable to ConocoPhillips for all periods presented includes income from discontinued operations as a result of the separation of the downstream business, the sale of our interest in Kashagan, and the sales of our Algeria and Nigeria businesses. These factors impact the comparability of this information. For additional information, see Note 3—Discontinued Operations, in the Notes to Consolidated Financial Statements.

See Management's Discussion and Analysis of Financial Condition and Results of Operations and the Notes to Consolidated Financial Statements for a discussion of factors that will enhance an understanding of this data.

## Item 7. 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 financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. 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 the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 72.*

*Due to discontinued operations reporting, income (loss) from continuing operations is more representative of ConocoPhillips' earnings. The terms "earnings" and "loss" as used in Management's Discussion and Analysis refer to income (loss) from continuing operations. For additional information, see Note* 3—*Discontinued Operations, in the Notes to Consolidated Financial Statements.*

## BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

ConocoPhillips is the world's largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. Headquartered in Houston, Texas, we have operations and activities in 21 countries. At December 31, 2015, we employed approximately 15,900 people worldwide and had total assets of $97.5 billion. Our stock is listed on the New York Stock Exchange under the symbol "COP."

### Basis of Presentation

Effective November 1, 2015, the Other International and historically presented Europe segments were restructured to align with changes to our internal organization structure. The Libya business was moved from the Other International segment to the historically presented Europe segment, which is now renamed Europe and North Africa. Accordingly, results of operations for the Other International and Europe and North Africa segments have been revised in all periods presented. There was no impact on our consolidated financial statements, and the impact on our segment presentation is immaterial. For additional information, see Note 24—Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements.

### Overview

We are an independent E&P company focused on exploring for, developing and producing crude oil and natural gas globally. Our diverse portfolio primarily includes resource-rich North American unconventional assets and oil sands assets in Canada; lower-risk legacy assets in North America, Europe, Asia and Australia; several major international developments; and an inventory of global conventional and unconventional exploration prospects.

The energy landscape changed dramatically in the past year. Increased supply caused commodity prices to decline substantially. In December 2015, we announced a 2016 operating plan based on $7.7 billion of capital expenditures. This represented a reduction of 24 percent, compared to 2015 actual expenditures, sourced from the completion of several major projects, as well as deferrals, deflation capture and efficiencies across the portfolio.

In response to an outlook of lower prices in 2016 compared to 2015, as well as credit tightening across the industry, we revised our 2016 operating plan in February 2016, reducing our capital expenditures guidance by 17 percent, from $7.7 billion to $6.4 billion. We also reduced our quarterly dividend by 66 percent, to $0.25 per share. These actions, taken to maintain a strong balance sheet, will enable us to continue to deliver an investment offering of a competitive dividend, disciplined growth and financial strength. We also believe these actions position the company for success in a lower, more volatile price environment, with the flexibility to adjust to commodity price movements in the future.

**Key Operating and Financial Summary**

Significant items during 2015 included the following:

- Achieved full-year production of 1,589 MBOED; 5 percent production growth from continuing operations, adjusted for Libya, downtime and dispositions.
- Lowered operating costs year over year.
- Reduced 2015 capital by 41 percent compared with 2014.
- Achieved major project startups at APLNG and Surmont 2.
- Completed additional startups at Eldfisk II, CD5, Drill Site 2S, Enochdhu and the Brodgar H3 subsea tie-back.
- Announced phased exit from deepwater exploration.
- Completed approximately $2 billion of non-core asset dispositions across the portfolio.
- Ended the year with $2.4 billion of cash and cash equivalents.

We accomplished several strategic milestones in 2015. Excluding Libya, our production from continuing operations was 1,589 MBOED, compared with 1,532 MBOED in 2014, a 57 MBOED increase. The production increase was driven by growth from major projects and development programs, as well as improved well performance, partially offset by normal field decline. In 2015, we generated $2 billion from the disposition of certain non-core assets in our portfolio. The full-year 2015 production impact of completed dispositions was 64 MBOED.

In 2015, we reviewed our cost structure and took decisive actions to achieve sustainable operating cost reductions across the company. We targeted a $1 billion reduction in operating costs in 2016, compared with 2014. We reduced headcount, including management positions, to streamline decision-making, increased the autonomy in our business units, captured deflation and adjusted our activity levels, which resulted in achieving our stated target in 2015, a year ahead of schedule. Operating costs include production and operating expense; selling, general and administrative expense; and exploration expense excluding dry hole and leasehold impairment expense.

We generated $7.6 billion in cash from continuing operations in 2015, paid dividends on our common stock of $3.7 billion and ended the year with $2.4 billion in cash and cash equivalents.

**Business Environment**

In the first half of 2014, strong crude oil prices were supported by geopolitical tensions impacting supplies, as well as global oil demand growth. This was followed by an abrupt decline in prices during the fourth quarter of 2014, as surging production growth from U.S. tight oil and the decision by the Organization of Petroleum Exporting Countries (OPEC) to maintain production outweighed fears of supply disruptions. These developments, combined with slowing global oil demand growth, caused crude oil prices to plummet to near five-year lows at the end of 2014. Prices remained significantly lower throughout 2015, reaching a ten-year quarterly low of $43.67 for Brent crude oil, in the fourth quarter of 2015. Lower 2015 prices contributed to higher demand growth which was overwhelmed by continued production increase and supply surplus. Brent crude oil was $30.69 in January 2016, reflecting an ongoing decline in prices.

The energy industry has periodically experienced this type of extreme volatility due to fluctuating supply-and-demand conditions. Commodity prices are the most significant factor impacting our profitability and related reinvestment of operating cash flows into our business. Among other dynamics that could influence world energy markets and commodity prices are global economic health, supply disruptions or fears thereof caused by civil unrest or military conflicts, actions taken by OPEC, environmental laws, tax regulations, governmental policies and weather-related disruptions. North America's energy landscape has been transformed from resource scarcity to an abundance of supply, primarily due to advances in technology responsible for the rapid growth of tight oil production, successful exploration and rising production from the Canadian oil sands. Our strategy is to sustainably lower our cost structure and maintain a strong balance sheet and a diverse low cost-of-supply portfolio that can provide the financial flexibility to withstand challenging business cycles.

*Operating and Financial Priorities*
Other important factors we must continue to manage well in order to be successful include:

- Maintaining a relentless focus on safety and environmental stewardship. Safety and environmental stewardship, including the operating integrity of our assets, remain our highest priorities, and we are committed to protecting the health and safety of everyone who has a role in our operations and the communities in which we operate. We strive to conduct our business with respect and care for both the local and global environment and systematically manage risk to drive sustainable business growth. Our sustainability efforts in 2015 focused on updating action plans for climate change, biodiversity, water and human rights, as well as revamping public reporting to be more informative, searchable and responsive to common questions. We are committed to building a learning organization using human performance principles as we relentlessly pursue improved Health, Safety and Environment (HSE) and operational performance.

  We are a founding member of the Marine Well Containment Company LLC (MWCC), a non-profit organization formed in 2010 to improve industry spill response in the U.S. Gulf of Mexico. MWCC developed a containment system, which meets the U.S. Bureau of Safety and Environmental Enforcement requirements for a subsea well containment system that can respond to a deepwater well control incident in the U.S. Gulf of Mexico. To complement this work internationally, we and several leading oil and gas companies established the Subsea Well Response Project in Norway, which enhances the oil industry's ability to respond to subsea well-control incidents in international waters.

- Exercising our capital flexibility. We participate in a commodity price-driven and capital-intensive industry, with varying lead times from when an investment decision is made to the time an asset is operational and generates cash flow. As a result, we must invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, and construct pipelines and liquefied natural gas (LNG) facilities. Given our view of greater price volatility, we see benefit in having an inventory of value-preserving, shorter cycle time and low cost-of-supply opportunities in our resource base. In response to weakening commodity prices, we have slowed the pace of certain discretionary investments, including the Eagle Ford and the Bakken, as well as emerging unconventional plays in the Permian, Niobrara and Montney, and plan to fund additional cash calls in our equity affiliates. We retain the flexibility to increase or decrease investment activity without loss of opportunity, and will reassess our near-term investment decisions as necessary. We use a disciplined approach, focused on value maximization, to set our capital plans.

  In February 2016, we announced a revised capital budget of $6.4 billion for 2016, a reduction of 37 percent compared with actual capital expenditures of $10.1 billion in 2015. The $3.7 billion reduction primarily reflects lower spending on major projects, deferral of activity primarily in the Lower 48, deflation capture and efficiencies across the portfolio.

- Portfolio optimization. We continue to optimize our asset portfolio by focusing on low cost-of-supply assets which strategically fit our development plans. In the third quarter of 2015, we announced plans to reduce future capital spending in our deepwater exploration program. As a result, we terminated our Gulf of Mexico deepwater drillship contract with Ensco and impaired certain Gulf of Mexico leases where we decided not to conduct further activity. Additionally, in the fourth quarter of 2015, we recorded dry hole expense and impaired additional leases in the Canada segment due to streamlined capital plans.

  In 2015, we generated approximately $2 billion in proceeds from non-core asset dispositions, including the sales of certain western Canadian properties, producing properties in East Texas and North Louisiana, producing properties in South Texas, a certain pipeline and gathering assets in South Texas, and our 50 percent equity method investment in the Russian joint venture, Polar Lights Company. We will continue to evaluate our assets to determine whether they fit our strategic direction and will optimize the portfolio as necessary, directing our capital investments to areas that align with our objectives.

- Controlling costs and expenses. Controlling operating and overhead costs, without compromising safety and environmental stewardship, is a high priority. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Managing operating and overhead costs is critical to maintaining a competitive position in our industry, particularly in a low commodity price environment.

- Adding to our proved reserve base. We primarily add to our proved reserve base in three ways:

  - Successful exploration, exploitation and development of new and existing fields.
  - Application of new technologies and processes to improve recovery from existing fields.
  - Acquisition of existing fields.

  Proved reserve estimates require economic production based on historical 12-month, first-of-month, average prices and current costs. Therefore, our proved reserves generally decrease as prices decline and increase as prices rise. Additionally, as we undertake cash conservation efforts, our reserve replacement efforts could be delayed thus limiting our ability to replace depleted reserves. Low commodity prices and reduced capital expenditures in 2015 adversely affected our reported year-end proved reserves. In 2015, our organic reserve replacement excluding the impact of sales and purchases was 10 percent. In the five years ended December 31, 2015, our organic reserve replacement was 117 percent, excluding the impact of sales and purchases.

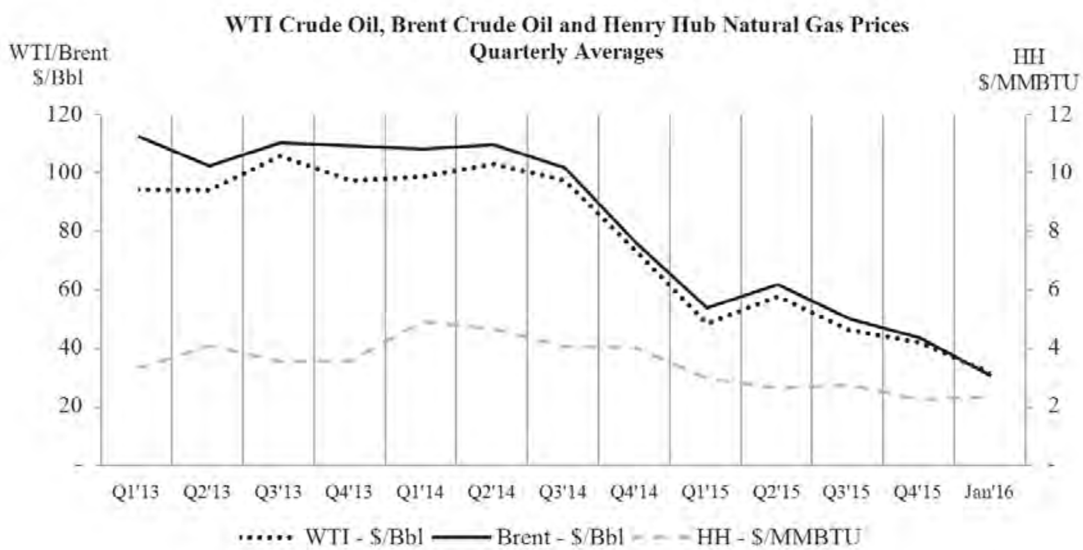
  Access to additional resources has become increasingly difficult as commodity prices can make projects uneconomic or unattractive. In addition, prohibition of direct investment in some nations, national fiscal terms, political instability, competition from national oil companies, and lack of access to high-potential areas due to environmental or other regulation may negatively impact our ability to increase our reserve base. As such, the timing and level at which we add to our reserve base may, or may not, allow us to replace our production over subsequent years.

- Applying technical capability. We leverage our knowledge and technology to create value and safely deliver on our plans. Technical strength is part of our heritage, and we are evolving our technical approach to optimally apply best practices. Companywide, we continue to evaluate potential solutions to leverage knowledge of technological successes across all of our operations. Such innovations enable us to economically convert additional resources to reserves, achieve greater operating efficiencies and reduce our environmental impact.

- Developing and retaining a talented work force. We strive to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics. To this end, we offer university internships across multiple disciplines to attract the best talent and, as needed, recruit experienced hires to maintain a broad range of skills and experience. We promote continued learning, development and technical training through structured development programs designed to enhance the technical and functional skills of our employees.

Other significant factors that can affect our profitability include:

- Commodity prices. Our earnings and operating cash flows generally correlate with industry price levels for crude oil and natural gas, the prices of which are subject to factors external to the company and over which we have no control. The following graph depicts the average benchmark prices for West Texas Intermediate (WTI) crude oil, Dated Brent crude oil and U.S. Henry Hub natural gas:




Crude oil prices have remained under pressure throughout 2015 due to continued global production increase that has outpaced demand growth, leading to a large observed rise in global inventory. Brent crude oil prices averaged $43.67 per barrel in the fourth quarter of 2015, a decrease of 43 percent compared with $76.27 per barrel in the fourth quarter of 2014. Similarly, WTI crude oil prices declined 43 percent from $73.41 per barrel in the fourth quarter of 2014 to $42.10 per barrel in the same period of 2015.

Henry Hub natural gas prices averaged $2.27 per million British thermal units (MMBTU) in the fourth quarter of 2015, a decrease of 44 percent compared with $4.04 per MMBTU in the fourth quarter of 2014. Natural gas prices remained under pressure as production growth continued and U.S. underground gas storage inventories rose to the top of the five-year range in late 2015.

Natural gas liquids prices were also lower in 2015. Our realized natural gas liquids prices averaged $16.42 per barrel in the fourth quarter of 2015, a decrease of 47 percent compared with $31.07 per barrel in the same quarter of 2014. The expansion in tight oil production has also helped boost supplies of natural gas liquids, resulting in continued downward pressure on natural gas liquids prices in the United States.

Declining global crude oil prices have resulted in the Western Canada Select benchmark price experiencing a 52 percent decline, from $73.60 per barrel in 2014 to $35.21 per barrel in 2015. Consequently, our realized bitumen price experienced a decrease relative to 2014 price levels. Our realized bitumen price was $18.72 per barrel in 2015, a decrease of 66 percent compared with $55.13 in the same period of 2014.

Our total average realized price from continuing operations was $34.34 per barrel of oil equivalent (BOE) in 2015, a decrease of 47 percent compared with $64.59 per BOE in 2014. Our total average realized price was $28.54 per BOE in the fourth quarter of 2015, a decrease of 46 percent compared with $52.88 per BOE in the fourth quarter of 2014. The reduction in the prices reflects lower average realized prices across all commodities.

In recent years, the use of hydraulic fracturing and horizontal drilling in tight oil formations has led to increased industry actual and forecasted crude oil and natural gas production in the United States. Although providing significant short- and long-term growth opportunities for our company, the increased abundance of crude oil and natural gas due to development of tight oil plays could also have adverse financial implications to us, including: an extended period of low commodity prices; production curtailments; delay of plans to develop areas such as unconventional fields or Alaska North Slope natural gas fields; and underutilization of LNG regasification facilities. Should one or more of these events occur, our revenues would be reduced and additional asset impairments might be possible.

Going forward, domestic crude prices should reach a market equilibrium with global crude prices due to the recent overturn of the U.S. crude export bans.

- Impairments. As mentioned above, we participate in capital-intensive industries. At times, our properties, plants and equipment and investments become impaired when, for example, commodity prices decline significantly for long periods of time, our reserve estimates are revised downward, or a decision to dispose of an asset leads to a write-down to its fair value. We may also invest large amounts of money in exploration which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. In 2015, we recorded pre-tax impairments of $2.2 billion for proved properties and an equity method investment and $1.9 billion for unproved properties, compared with $856 million and $562 million in 2014. For additional information on our impairments in 2015, 2014 and 2013, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

- Effective tax rate. Our operations are located in countries with different tax rates and fiscal structures. Accordingly, even in a stable commodity price and fiscal/regulatory environment, our overall effective tax rate can vary significantly between periods based on the "mix" of pretax earnings within our global operations.

- Fiscal and regulatory environment. Our operations can be affected by changing economic, regulatory and political environments in the various countries in which we operate, including the United States. Civil unrest or strained relationships with governments may impact our operations or investments. These changing environments have generally negatively impacted our results of operations, and further changes to government fiscal take could have a negative impact on future operations. Our production operations in Libya and related oil exports have been suspended or significantly curtailed since July 2013 due to the closure of the Es Sider crude oil export terminal, and they were also suspended in 2011 during Libya's period of civil unrest. In 2015, the United Kingdom government enacted tax legislation which reduced our U.K. corporate tax rate by 12 percent, while the Alberta provincial government enacted legislation increasing our overall Canadian corporate tax rate by 2 percent. Our assets in Venezuela and Ecuador were expropriated in 2007 and 2009, respectively. Our management carefully considers these events when evaluating projects or determining the level of activity in such countries.

**Outlook**

Consistent with our revised 2016 operating plan announced in February 2016, our full-year 2016 production from continuing operations is expected to be flat with 2015 production of 1,525 MBOED, which excludes 64 MBOED for the full-year impact of completed dispositions. First-quarter 2016 production from continuing operations is expected to be 1,540 MBOED to 1,580 MBOED.

*Marketing Activities*
In line with our objective to continuously optimize our portfolio, we are currently marketing certain non-core assets. We expect to generate up to $1 billion in proceeds annually from asset sales.

*Impairments*
As a result of lower commodity prices, and as we optimize our investments and exercise capital flexibility, it is reasonably likely we may incur future impairment charges to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method, and unproved properties. Although it is not reasonably practicable to quantify the impact of future impairment charges at this time, our results of operations could be materially adversely affected for the period in which impairment charges are incurred.

**Operating Segments**

We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, corporate overhead, certain technology activities, as well as licensing revenues received.

Our key performance indicators, shown in the statistical tables provided at the beginning of the operating segment sections that follow, reflect results from our continuing operations, including commodity prices and production.

## RESULTS OF OPERATIONS

### Consolidated Results

A summary of the company's income (loss) from continuing operations by business segment follows:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| Years Ended December 31 | | **2015** | 2014 | 2013 |
| Alaska | $ | **4** | 2,041 | 2,274 |
| Lower 48 | | **(1,932)** | (22) | 754 |
| Canada | | **(1,044)** | 940 | 718 |
| Europe and North Africa | | **409** | 814 | 1,297 |
| Asia Pacific and Middle East | | **(406)** | 3,008 | 3,591 |
| Other International | | **(593)** | (100) | 223 |
| Corporate and Other | | **(809)** | (874) | (820) |
| Income (loss) from continuing operations | $ | **(4,371)** | 5,807 | 8,037 |

*2015 vs. 2014*

Earnings for ConocoPhillips decreased 175 percent in 2015. The decrease was mainly due to lower commodity prices.

In addition, earnings were negatively impacted by:

- Higher proved property and equity investment impairments, including a $1.5 billion before- and after-tax impairment of our equity investment in APLNG.
- Higher exploration expenses. Exploration expenses increased mainly as a result of higher unproved property impairments, dry hole costs and other exploration expenses. The increase included after-tax unproved property impairments of $368 million for our Alaska Chukchi Sea leasehold and capitalized interest, $310 million for our Angola Block 36 and 37 Production Sharing Contracts (PSCs), $154 million for multiple Gulf of Mexico leases, and $100 million for various Gila Prospect blocks. Additional after-tax dry hole costs and other expenses resulted from a $185 million charge for several properties in Canada, $137 million for two dry holes in Angola, $111 million for a dry hole in the Gila Prospect in deepwater Gulf of Mexico, and $246 million related to the termination of our drilling contract with Ensco.
- Higher depreciation, depletion and amortization (DD&A), mainly from increased production and commodity price-driven reserve revisions.
- Higher restructuring charges and pension settlement expense.

These reductions to earnings were partly offset by higher sales volumes, lower production taxes due to reduced commodity prices, lower operating expenses, a $555 million net deferred tax benefit resulting from a change in the U.K. tax rate in the first quarter of 2015, the absence of a $540 million after-tax loss resulting from the Freeport LNG termination agreement, gain on sale of assets, and higher licensing revenue.

*2014 vs. 2013*

Earnings for ConocoPhillips decreased 28 percent in 2014. The decrease was mainly due to:

- Lower crude oil prices.
- Lower gains from asset sales. Gains realized in 2014 were approximately $70 million after-tax, compared with gains realized in 2013 of $1,132 million after-tax.
- Higher operating expenses, which included the 2014 recognition of a $540 million after-tax loss resulting from the Freeport LNG termination agreement.

- Higher impairments. Noncash impairments in 2014 totaled $662 million after-tax, compared with $289 million after-tax in 2013.
- Higher DD&A expenses, mainly due to higher volumes in the Lower 48 and the United Kingdom, partly offset by lower unit-of-production rates in Canada related to reserve bookings.
- Higher exploration expenses.

These reductions to earnings were partially offset by higher volumes; lower production taxes, which mainly resulted from higher capital spending, lower prices and lower production volumes in Alaska; and higher natural gas and LNG prices.

**Income Statement Analysis**

*2015 vs. 2014*

Sales and other operating revenues decreased 44 percent in 2015, mainly as a result of lower prices across all commodities. Lower prices were partly offset by higher crude oil and LNG sales volumes.

Equity in earnings of affiliates decreased 74 percent in 2015. The decrease was primarily due to lower earnings from FCCL Partnership and Qatar Liquefied Gas Company Limited (3) (QG3), given lower commodity prices, partly offset by higher volumes and lower operational costs.

Gain on dispositions increased by $493 million in 2015. The increase resulted from a $583 million gain from the sales of producing properties in East Texas and North Louisiana, South Texas, and a certain pipeline and gathering assets in South Texas. Gains realized were partly offset by a net loss from the disposition of non-core assets in western Canada. For additional information on gains on dispositions, see Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

Other income decreased 66 percent in 2015, mainly due to the absence of 2014 income related to the resolution of a contingent liability in the Other International segment and a legal arbitration settlement in Asia Pacific and Middle East, respectively.

Purchased commodities decreased 44 percent in 2015, largely as a result of lower natural gas prices and the absence of a $130 million loss in the Lower 48 related to transportation and storage capacity agreements recognized in 2014.

Production and operating expenses decreased 21 percent in 2015, largely due to lower operating expense activity, including reduced turnarounds at our Bayu-Undan Field and Darwin LNG facility, favorable foreign exchange-related impacts, and the absence of an $849 million charge resulting from the Freeport LNG termination agreement in 2014. The decrease in expense was partially offset by restructuring expenses of $206 million in 2015.

Selling, general and administrative (SG&A) expenses increased 30 percent in 2015, primarily due to $407 million in restructuring and pension settlement expenses in 2015, partially offset by lower staff and compensation plan costs.

Exploration expenses increased 105 percent in 2015, mainly as a result of higher unproved property impairments, primarily in Alaska, Angola and the Lower 48. Higher dry hole and other exploration costs, including a $253 million pre-tax expense for wells charged to dry hole in Canada, a $383 million expense related to the termination of our Gulf of Mexico deepwater drillship contract, and a $176 million charge for two wells charged to dry hole in the Gila prospect in the deepwater Gulf of Mexico, also contributed to the increase in exploration expenses. For additional information on leasehold impairments and other exploration expenses, see Note 8—Suspended Wells and Other Exploration Expenses, and Note 9—Impairments, in the Notes to Consolidated Financial Statements.

DD&A increased 9 percent in 2015. The increase was mainly associated with higher production volumes in the Lower 48 and Asia Pacific and Middle East and commodity price-related reserve revisions. The increase was partly offset by reserve additions in the Lower 48.

Impairments increased 162 percent in 2015. For additional information, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes decreased 57 percent in 2015, mainly due to lower production taxes from reduced commodity prices in the Lower 48, Alaska and Asia Pacific and Middle East.

Interest and debt expense increased 42 percent in 2015, primarily due to lower capitalized interest on projects and increased average debt levels in 2015.

See Note 19—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our provision for income taxes and effective tax rate.

*2014 vs. 2013*

Sales and other operating revenues decreased 3 percent in 2014, mainly as a result of lower crude oil prices, partly offset by higher crude oil and bitumen volumes and higher natural gas prices.

Equity in earnings of affiliates increased 14 percent in 2014, primarily as a result of higher earnings from FCCL Partnership due to higher bitumen volumes and prices. This increase was partially offset by lower earnings from APLNG, mostly as a result of higher operating expenses and DD&A.

Gain on dispositions decreased $1,144 million in 2014. Gains realized in 2014 mostly resulted from the disposition of certain properties in western Canada. For additional information on gains realized in prior years, see Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

Production and operating expenses increased 23 percent in 2014, largely due to the $849 million charge resulting from the Freeport LNG termination agreement. Higher drilling and maintenance activity, mostly in the Lower 48, Australia, Alaska and Europe, in addition to the absence of the 2013 benefit of a $142 million accrual reduction related to the Federal Energy Regulatory Commission (FERC) approval of cost allocation (pooling) agreements with the remaining owners of the Trans-Alaska Pipeline System (TAPS), also contributed to the increase. These increases were partly offset by the absence of a $155 million charge in 2013 related to Bohai Bay. For additional information on the Freeport LNG transaction, see Note 7—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

SG&A expenses decreased 14 percent in 2014, mainly due to the absence of pension settlement expenses.

Exploration expenses increased 66 percent in 2014, mainly as a result of higher impairments of undeveloped leasehold costs, primarily in the Lower 48 and Canada, and higher dry hole costs, mostly associated with the Gulf of Mexico and Angola. For additional information on the leasehold impairments, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

DD&A increased 12 percent in 2014. This increase was mostly associated with higher production volumes in the United Kingdom and the Lower 48, partly offset by lower unit-of-production rates in Canada associated with year-end 2013 price-related reserve revisions and lower natural gas production volumes.

Impairments increased 62 percent in 2014. For additional information, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes decreased 28 percent in 2014, mainly due to lower production taxes, which resulted from higher capital spending, lower crude oil prices and lower production volumes in Alaska.

Interest and debt expense increased 6 percent in 2014, primarily due to lower capitalized interest on projects, partly offset by lower interest expense from lower average debt levels and a $28 million benefit associated with interest on a favorable tax settlement.

See Note 19—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our provision for income taxes and effective tax rate.

**Summary Operating Statistics**

| | | 2015 | 2014 | 2013 |
|---|---|---|---|---|
| **Average Net Production** | | | | |
| Crude oil (MBD)* | | **605** | 595 | 581 |
| Natural gas liquids (MBD) | | **156** | 159 | 156 |
| Bitumen (MBD) | | **151** | 129 | 109 |
| Natural gas (MMCFD)** | | **4,060** | 3,943 | 3,939 |
| **Total Production** (MBOED)*** | | **1,589** | 1,540 | 1,502 |
| | | Dollars Per Unit | | |
| **Average Sales Prices** | | | | |
| Crude oil (per barrel) | $ | **48.26** | 92.80 | 103.32 |
| Natural gas liquids (per barrel) | | **17.79** | 38.99 | 41.42 |
| Bitumen (per barrel) | | **18.72** | 55.13 | 53.27 |
| Natural gas (per thousand cubic feet) | | **3.96** | 6.57 | 6.11 |
| | | Millions of Dollars | | |
| **Worldwide Exploration Expenses** | | | | |
| General and administrative; geological and geophysical; and lease rentals | $ | **1,127** | 879 | 789 |
| Leasehold impairment | | **1,924** | 562 | 175 |
| Dry holes | | **1,141** | 604 | 268 |
| | $ | **4,192** | 2,045 | 1,232 |

*Excludes discontinued operations.*
**Thousands of barrels per day.*
***Millions of cubic feet per day. Represents quantities available for sale and excludes gas equivalent of natural gas liquids included above.*
****Thousands of barrels of oil equivalent per day.*

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2015, our continuing operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia and Qatar.

Total production from continuing operations, including Libya, increased 3 percent in 2015. The increase in total average production in 2015 primarily resulted from additional production from major developments, including tight oil plays in the Lower 48; Gumusut in Malaysia; APLNG in Australia; Greater Britannia projects and the J-Area in the U.K.; and the ramp-up of Foster Creek Phase F in Canada. Improved well performance, mostly in the Lower 48, western Canada and Norway, and lower turnaround activity also contributed to higher production in 2015. These increases were largely offset by normal field decline. Adjusted for downtime and dispositions of 13 MBOED, our production from continuing operations, excluding Libya, increased by 70 MBOED, or 5 percent, compared with 2014. Full-year 2015 production from assets sold or under agreement was 64 MBOED.

In 2014, average production from continuing operations increased 3 percent compared with 2013, while average liquids production increased 4 percent. The increase in total average production in 2014 primarily resulted from additional production from major developments, mainly from tight oil plays in the Lower 48 and the ramp up of production from Jasmine in the United Kingdom and Christina Lake in Canada, and increased drilling programs, mostly in the Lower 48, western Canada and Norway. These increases were largely offset by normal field decline, higher planned downtime, shut-in Libya production due to the closure of the Es Sider crude oil export terminal, and unfavorable market impacts. Adjusted for Libya, production from continuing operations increased by 60 MBOED, or 4 percent, compared with 2013.

## Alaska

| | | 2015 | 2014 | 2013 |
|---|---|---|---|---|
| **Income from Continuing Operations** (millions of dollars) | $ | **4** | 2,041 | 2,274 |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **158** | 162 | 178 |
| Natural gas liquids (MBD) | | **13** | 13 | 15 |
| Natural gas (MMCFD) | | **42** | 49 | 43 |
| **Total Production** (MBOED) | | **178** | 183 | 200 |
| **Average Sales Prices** | | | | |
| Crude oil (per barrel) | $ | **51.61** | 97.68 | 107.83 |
| Natural gas (per thousand cubic feet) | | **4.33** | 5.42 | 4.35 |

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids, natural gas and LNG. In 2015, Alaska contributed 19 percent of our worldwide liquids production and 1 percent of our natural gas production.

*2015 vs. 2014*

Alaska reported earnings of $4 million in 2015, compared with earnings of $2,041 million in 2014, mainly due to lower commodity prices and a $368 million after-tax charge in the fourth quarter of 2015 for the impairment of our Chukchi Sea leasehold and capitalized interest. The earnings decrease was partly offset by reduced production taxes resulting from lower commodity prices.

Average production decreased 3 percent in 2015 compared with 2014, primarily due to normal field decline, partly offset by lower planned downtime activity and new production from the Western North Slope, Greater Prudhoe and Greater Kuparuk areas.

*2014 vs. 2013*

Alaska earnings decreased 10 percent in 2014 compared with 2013 earnings. The decrease was largely due to lower crude oil prices and volumes; the absence of a $97 million after-tax benefit associated with a FERC ruling in 2013, more fully described below; higher operating expenses; and a $36 million after-tax impairment related to a cancelled project. These reductions to earnings were partly offset by lower production taxes, which resulted from higher 2014 capital spending and lower crude oil prices and volumes. Higher LNG sales volumes and prices also partially offset the decrease in 2014 earnings.

In 2012, the major owners of TAPS filed a proposed settlement with FERC to resolve pooling disputes prior to August 2012 and establish a voluntary pooling agreement to pool costs prospectively from August 2012. In July 2013, FERC approved the proposed settlement and pooling agreement without modification. As a result, we reduced a related accrual in the second quarter of 2013, which decreased our production and operating expenses by $97 million after-tax.

Average production decreased 9 percent in 2014 compared with 2013, mainly as a result of normal field decline and higher planned maintenance, partly offset by lower unplanned downtime.

**Lower 48**

| | | 2015 | 2014 | 2013 |
|---|---|---|---|---|
| **Income (Loss) from Continuing Operations** (millions of dollars) | $ | **(1,932)** | (22) | 754 |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **206** | 188 | 152 |
| Natural gas liquids (MBD) | | **94** | 97 | 91 |
| Natural gas (MMCFD) | | **1,472** | 1,491 | 1,490 |
| **Total Production** (MBOED) | | **545** | 533 | 491 |
| **Average Sales Prices** | | | | |
| Crude oil (per barrel) | $ | **42.62** | 84.18 | 93.79 |
| Natural gas liquids (per barrel) | | **14.01** | 30.74 | 31.48 |
| Natural gas (per thousand cubic feet) | | **2.43** | 4.29 | 3.50 |

The Lower 48 segment consists of operations located in the U.S. Lower 48 states and exploration activities in the Gulf of Mexico. During 2015, the Lower 48 contributed 33 percent of our worldwide liquids production and 36 percent of our natural gas production.

*2015 vs. 2014*

Lower 48 reported a loss of $1,932 million after-tax in 2015, compared with a loss of $22 million after-tax in 2014. The decrease in earnings was primarily due to:

- Lower crude oil, natural gas and natural gas liquids prices.
- Higher DD&A, mostly due to increased crude oil production.
- Higher exploration expenses
    - Increased impairment expense in 2015, including after-tax charges of $154 million for certain leases in the Gulf of Mexico and $100 million for various blocks in the Gila Prospect, where we ceased further activity.
    - A $246 million charge to exploration expense related to the termination of our Gulf of Mexico deepwater drillship contract with Ensco.
    - Higher dry hole costs, including $111 million associated with two wells in the Gila Prospect in the deepwater Gulf of Mexico.

These decreases were partly offset by the absence of a $545 million after-tax charge resulting from the Freeport LNG termination agreement in 2014; a $368 million after-tax gain from the disposition of certain properties in South Texas, East Texas and Northern Louisiana; higher volumes; lower production taxes; and the absence of a $151 million after-tax impairment charge resulting from reduced volume forecasts on proved properties and the associated undeveloped leasehold costs.

Our average realized prices in the Lower 48 have historically correlated with WTI prices; however, beginning in the second half of 2013, our Lower 48 crude differential versus WTI began to widen. Our 2015 average realized crude oil price of $42.62 per barrel was 13 percent less than WTI of $48.72 per barrel. The differential is driven primarily by local market dynamics in the Gulf Coast, Bakken and the Permian Basin, and may remain relatively wide in the near-term.

Total average production increased 2 percent in 2015 compared with 2014, while average crude oil production increased 10 percent across the same period. The increase was mainly attributable to new production, primarily from Eagle Ford, Bakken and the Permian Basin, partially offset by normal field decline.

*2014 vs. 2013*

The Lower 48 reported a loss of $22 million after-tax in 2014, compared with earnings of $754 million after-tax in 2013. The decrease in earnings was primarily attributable to:

- Higher operating expenses, which included the $545 million after-tax charge to earnings due to the Freeport LNG termination agreement.
- Lower crude oil prices.
- Higher DD&A, mostly due to higher crude oil production.
- Higher impairments. Earnings in 2014 were impacted by impairments of approximately $290 million after-tax. Property impairments were not material in 2013. For additional information, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.
- Higher dry hole costs. Dry hole costs in 2014 were approximately $180 million after-tax, primarily for the nonoperated Coronado wildcat and appraisal wells, the Shenandoah appraisal well and the Deep Nansen wildcat well, all located in the Gulf of Mexico. Dry hole costs in 2013 were approximately $130 million after-tax and mainly consisted of the Ardennes and Thorn wells, also located in the Gulf of Mexico.
- An $83 million after-tax loss recognized upon the release of underutilized transportation and storage capacity at rates below our contractual rates.

These reductions to earnings were partially offset by higher crude oil and natural gas liquids volumes, higher natural gas prices and a benefit to earnings of approximately $150 million after-tax from marketing third-party natural gas volumes.

Total average production in the Lower 48 increased 9 percent in 2014, while average crude oil production increased 24 percent. The increase was mainly attributable to new production, primarily from the Eagle Ford and Bakken, and improved drilling and well performance, partially offset by normal field decline.

**Canada**

| | | 2015 | 2014 | 2013 |
|---|---|---|---|---|
| **Income (Loss) from Continuing Operations** (millions of dollars) | $ | **(1,044)** | 940 | 718 |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **12** | 13 | 13 |
| Natural gas liquids (MBD) | | **26** | 23 | 25 |
| Bitumen (MBD) | | | | |
| Consolidated operations | | **13** | 12 | 13 |
| Equity affiliates | | **138** | 117 | 96 |
| Total bitumen | | **151** | 129 | 109 |
| Natural gas (MMCFD) | | **715** | 711 | 775 |
| **Total Production** (MBOED) | | **308** | 284 | 276 |
| **Average Sales Prices** | | | | |
| Crude oil (per barrel) | $ | **39.52** | 77.87 | 79.73 |
| Natural gas liquids (per barrel) | | **17.02** | 46.23 | 47.19 |
| Bitumen (dollars per barrel) | | | | |
| Consolidated operations | | **20.13** | 60.03 | 55.25 |
| Equity affiliates | | **18.58** | 54.62 | 53.00 |
| Total bitumen | | **18.72** | 55.13 | 53.27 |
| Natural gas (per thousand cubic feet) | | **1.91** | 4.13 | 2.92 |

Our Canadian operations mainly consist of natural gas fields in western Canada and oil sands developments in the Athabasca Region of northeastern Alberta. In 2015, Canada contributed 21 percent of our worldwide liquids production and 18 percent of our worldwide natural gas production.

*2015 vs. 2014*

Canada operations reported a loss of $1,044 million in 2015, a reduction of $1,984 million compared with 2014. The decrease in earnings was primarily due to:

- Lower bitumen and natural gas prices.
- Higher exploration expenses
    - Higher dry hole costs, including an after-tax charge of $185 million associated with our Horn River, Northwest Territories, Thornbury and Saleski properties.
    - An after-tax impairment charge of $75 million for undeveloped leasehold in the Duvernay, Thornbury, Saleski and Crow Lake areas.
- A 2 percent increase in Alberta corporate tax rates on deferred taxes.
- A $103 million net after-tax loss realized on the disposition of non-core assets in western Canada.

The earnings decrease was partly offset by higher bitumen production volumes; lower operating expenses and DD&A, both primarily from favorable foreign currency impacts; and the absence of the $109 million after-tax impairment of undeveloped leasehold costs associated with the offshore Amauligak discovery, Arctic Islands and other Beaufort properties in 2014.

Total average production increased 8 percent in 2015 compared with 2014, while bitumen production increased 17 percent over the same periods. The increases in total production were mainly attributable to strong well performance in western Canada, lower royalty impacts, strong plant performance at Foster Creek and Christina Lake and the continued ramp-up of production from Foster Creek Phase F. These increases were partly offset by normal field decline and increased unplanned downtime, including the precautionary shut down of Foster Creek for nearby forest fires in the second quarter of 2015.

*2014 vs. 2013*

Canada earnings increased 31 percent in 2014 compared with 2013, primarily as a result of higher natural gas and bitumen prices, lower DD&A from western Canada and higher bitumen volumes. The lower DD&A mainly resulted from lower unit-of-production rates related to year-end 2013 price-related reserve revisions and lower natural gas production volumes. Earnings in 2014 also included a $47 million tax benefit resulting from a favorable tax settlement. These increases were partly offset by lower gains from asset sales, mainly as a result of the $461 million after-tax gain from the disposition of our Clyden undeveloped oil sands leasehold in 2013, as well as the 2013 recognition of a $224 million tax benefit, related to the favorable tax resolution associated with the sale of certain western Canada properties. Lower natural gas volumes also partially offset the increase in 2014 earnings.

In addition, earnings in 2014 benefitted from lower impairments. Impairments in 2014 were $138 million after-tax and consisted primarily of the $109 million after-tax impairment of unproved properties associated with the offshore Amauligak discovery, Arctic Islands and other Beaufort properties. Impairments in 2013 consisted of the $162 million after-tax impairment of mature natural gas assets in western Canada.

For additional information on asset sales, see Note 6—Assets Held for Sale or Sold, and for additional information on impairments, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Total average production increased 3 percent in 2014 compared with 2013, while bitumen production increased 18 percent over the same period. The continued ramp-up of production from Christina Lake Phase E in FCCL and improved drilling and well performance were partly offset by normal field decline and higher royalty impacts.

**Europe and North Africa**

| | | **2015** | 2014 | 2013 |
|---|---|---|---|---|
| **Income from Continuing Operations** (millions of dollars) | $ | **409** | 814 | 1,297 |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **120** | 134 | 139 |
| Natural gas liquids (MBD) | | **7** | 8 | 6 |
| Natural gas (MMCFD) | | **476** | 464 | 441 |
| **Total Production** (MBOED) | | **207** | 219 | 219 |
| **Average Sales Prices** | | | | |
| Crude oil (dollars per barrel) | $ | **52.75** | 98.98 | 109.96 |
| Natural gas liquids (per barrel) | | **27.56** | 52.65 | 58.36 |
| Natural gas (per thousand cubic feet) | | **7.14** | 9.28 | 10.41 |

The Europe and North Africa segment consists of producing and exploration operations principally located in the Norwegian and U.K. sectors of the North Sea, the Norwegian Sea, as well as in Libya. In 2015, our Europe and North Africa operations contributed 14 percent of our worldwide liquids production and 12 percent of our natural gas production.

*2015 vs. 2014*

Earnings for Europe and North Africa operations decreased 50 percent in 2015. The decrease in earnings was primarily due to lower crude oil and natural gas prices. Earnings further decreased due to higher property impairments in the U.K., given lower natural gas prices and increases to asset retirement obligations. The earnings decrease was partly offset by a $555 million net deferred tax benefit as a result of a change in the U.K. tax rate, effective at the beginning of 2015, and an after-tax gain of $49 million realized on the sale of our 1.9 percent interest in Norwegian Continental Shelf Gas Transportation (Gassled).

For additional information on the impairments, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Average production decreased 5 percent in 2015, compared with 2014. The decrease in production was mostly due to normal field decline and lower volumes from Libya, partly offset by the new production from the Greater Britannia Area, the J-Area and the Greater Ekofisk Area, as well as improved well performance in Norway.

The Es Sider Terminal in Libya remained shut in throughout 2015. The 2016 operating and drilling activity in Libya is uncertain as a result of the ongoing civil unrest.

*2014 vs. 2013*

Earnings for Europe and North Africa decreased 37 percent in 2014 compared with 2013. The reduction in earnings was primarily due to higher DD&A, which mainly resulted from increased production volumes from Jasmine, lower crude oil and natural gas prices, higher taxes, higher impairments, and lower volumes from Libya. Impairments in 2014 were $192 million after-tax, compared with impairments in 2013 of $118 million after-tax. Lower gains from asset dispositions, mostly due to the absence of the $83 million after-tax gain on the disposition of our interest in the Interconnector Pipeline in 2013, also contributed to the decrease in 2014 earnings. These decreases were partly offset by higher volumes, primarily in the U.K., and a $48 million after-tax benefit from a pension-related settlement.

For additional information on the impairments, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Average production was flat in 2014 compared with 2013, as the continued ramp-up of production from Jasmine, the Rivers Acid Plant in the East Irish Sea and Ekofisk South, improved drilling and well performance in Norway and lower planned downtime, were equally offset by normal field decline and the shutdown of the Es Sider crude oil export terminal in Libya.

### Asia Pacific and Middle East

| | | **2015** | 2014 | 2013 |
|---|---|---|---|---|
| **Income (Loss) from Continuing Operations** (millions of dollars) | $ | **(406)** | 3,008 | 3,591 |
| | | | | |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | | | |
| Consolidated operations | | **91** | 79 | 80 |
| Equity affiliates | | **14** | 15 | 15 |
| Total crude oil | | **105** | 94 | 95 |
| | | | | |
| Natural gas liquids (MBD) | | | | |
| Consolidated operations | | **9** | 10 | 12 |
| Equity affiliates | | **7** | 8 | 7 |
| Total natural gas liquids | | **16** | 18 | 19 |
| | | | | |
| Natural gas (MMCFD) | | | | |
| Consolidated operations | | **717** | 723 | 709 |
| Equity affiliates | | **638** | 505 | 481 |
| Total natural gas | | **1,355** | 1,228 | 1,190 |
| | | | | |
| **Total Production** (MBOED) | | **347** | 317 | 312 |
| | | | | |
| **Average Sales Prices** | | | | |
| Crude oil (dollars per barrel) | | | | |
| Consolidated operations | $ | **49.70** | 95.32 | 104.78 |
| Equity affiliates | | **53.12** | 99.01 | 105.44 |
| Total crude oil | | **50.16** | 95.92 | 104.88 |
| Natural gas liquids (dollars per barrel) | | | | |
| Consolidated operations | | **37.78** | 69.36 | 73.82 |
| Equity affiliates | | **35.79** | 67.20 | 73.31 |
| Total natural gas liquids | | **36.88** | 68.46 | 73.63 |
| Natural gas (dollars per thousand cubic feet) | | | | |
| Consolidated operations | | **6.23** | 9.80 | 10.61 |
| Equity affiliates | | **4.83** | 9.79 | 8.98 |
| Total natural gas | | **5.58** | 9.80 | 9.95 |

The Asia Pacific and Middle East segment has operations in China, Indonesia, Malaysia, Australia, Timor-Leste and Qatar, as well as exploration activities in Brunei. During 2015, Asia Pacific and Middle East contributed 13 percent of our worldwide liquids production and 33 percent of our natural gas production.

*2015 vs. 2014*

Asia Pacific and Middle East reported a loss of $406 million in 2015, compared with income of $3,008 million in 2014. The decrease in earnings was mainly due to lower prices across all commodities. Earnings in 2015 were further decreased by a $1,502 million before- and after-tax charge for the impairment of our APLNG investment, higher DD&A expense from increased volumes, primarily in Malaysia, and a $41 million after-tax charge for the impairment of our relinquished Palangkaraya PSC. The earnings decrease was partially offset by lower production taxes, increased volumes, as well as lower feedstock costs and reduced turnarounds at our Bayu-Undan Field and Darwin LNG facility.

See the “APLNG” section of Note 7—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for information on the impairment of our APLNG investment included within the Asia Pacific and Middle East segment.

Average production increased 9 percent in 2015, compared with 2014. The production increase was mainly attributable to new production from Gumusut, in Malaysia, which came online in the fourth quarter of 2014; the ramp-up of APLNG production due to additional gas processing facilities online; and infill drilling in China. Production increases were partly offset by normal field decline.

*2014 vs. 2013*

Asia Pacific and Middle East earnings decreased 16 percent in 2014 compared with 2013. The reduction in earnings was largely due to lower crude oil and natural gas prices; higher operating expenses, mostly as a result of major planned maintenance at our Bayu-Undan Field and Darwin LNG facility in Australia; lower equity earnings, mainly due to increased activity at APLNG in preparation for startup in 2015; and lower sales volumes, primarily crude oil and LNG. These decreases were partially offset by higher LNG prices, higher natural gas volumes and lower taxes. The 2014 benefits from the absence of the $116 million after-tax charge in 2013 related to Bohai Bay and a $30 million after-tax legal settlement in 2014 were offset by the absence of a $146 million after-tax insurance settlement received in 2013, also associated with the Bohai Bay seepage incidents.

Average production increased 2 percent in 2014 compared with 2013. Increased production, mainly from Indonesia, China and Malaysia, was largely offset by normal field decline and major planned maintenance at Bayu-Undan and Darwin LNG.

**Other International**

| | | **2015** | 2014 | 2013 |
|---|---|---|---|---|
| **Income (Loss) from Continuing Operations** (millions of dollars) | $ | **(593)** | (100) | 223 |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | | | |
| Equity affiliates | | **4** | 4 | 4 |
| **Total Production** (MBOED) | | **4** | 4 | 4 |
| **Average Sales Prices** | | | | |
| Crude oil (dollars per barrel) | | | | |
| Equity affiliates | | **37.21** | 64.14 | 72.43 |

The Other International segment includes exploration activities in Colombia, Angola and Senegal. In 2015, Other International contributed less than 1 percent of our worldwide liquids production. In the fourth quarter of 2015, we completed the sale of our 50 percent interest in the Polar Lights Company.

*2015 vs. 2014*

Other International operations reported a loss of $593 million in 2015, compared with a loss of $100 million in 2014. The decrease in earnings was primarily due to after-tax charges of $235 million, $75 million and $32 million net for property impairments on our Angola Block 36, Angola Block 37 and Poland leasehold, respectively. Earnings were also reduced due to increased dry hole expenses for the Omosi-1 and Vali-1 wells in Angola and the absence of other income of $154 million after-tax associated with the favorable resolution of a contingent liability. The reduction in earnings was partly offset by the absence of the $136 million after-tax charge in 2014 for the Kamoxi-1 exploration well, located offshore Angola; and a $53 million after-tax gain from the disposition of our interest in the Polar Lights Company.

For additional information on the impairments, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Average production was flat in 2015 compared with 2014.

*2014 vs. 2013*

Other International operations reported a loss of $100 million in 2014, compared with earnings of $223 million in 2013. The decrease was primarily due to the lower gains from asset dispositions, mainly from the absence of the $288 million after-tax gain recognized on the 2013 disposition of our equity investment in Phoenix Park Processors Limited, located in Trinidad and Tobago and higher dry hole expenses, mostly due to the $136 million after-tax charge for the Kamoxi-1 exploration well, located offshore Angola. These reductions were partially offset by the recognition of other income of $154 million after-tax associated with the favorable resolution of a contingent liability.

Average production was flat in 2014 compared with 2013.

**Corporate and Other**

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| **Income (Loss) from Continuing Operations** | | | | |
| Net interest | $ | **(518)** | (502) | (530) |
| Corporate general and administrative expenses | | **(246)** | (194) | (213) |
| Technology | | **122** | (93) | (6) |
| Other | | **(167)** | (85) | (71) |
| | $ | **(809)** | (874) | (820) |

*2015 vs. 2014*

Net interest consists of interest and financing expense, net of interest income and capitalized interest, as well as premiums incurred on the early retirement of debt. Net interest increased 3 percent in 2015 compared with 2014, primarily as a result of lower capitalized interest on projects completed or sold and increased debt. The 2015 net interest expense increase was largely offset by a $148 million net tax benefit for electing the fair market value method of apportioning interest expense in the United States for prior years.

Corporate general and administrative expenses increased 27 percent in 2015, mainly due to $143 million in after-tax pension settlement expense, partially offset by lower staff and compensation plan costs.

Technology includes our investment in new technologies or businesses, as well as licensing revenues received. Activities are focused on heavy oil and oil sands, unconventional reservoirs, LNG, and subsurface, arctic and deepwater technologies, with an underlying commitment to environmental responsibility. Earnings from Technology were $122 million in 2015, compared with losses of $93 million in 2014. The increase in earnings primarily resulted from higher licensing revenues.

The category "Other" includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, and other costs not directly associated with an operating segment. "Other" expenses increased by $82 million in 2015, mainly due to $142 million after-tax in restructuring charges and foreign currency translation impacts, partially offset by lower environmental expenses.

*2014 vs. 2013*

Net interest decreased 5 percent in 2014 compared with 2013, primarily as a result of a $93 million tax benefit associated with the election of the fair market value method of apportioning interest expense in the United States, as well as a $28 million after-tax benefit associated with interest on a favorable tax settlement. These improvements were largely offset by lower capitalized interest on projects sold or completed.

Corporate general and administrative expenses decreased 9 percent in 2014, mainly due to lower pension settlement expense, partly offset by higher benefit-related expenses. Pension settlement expense incurred in 2013 was $41 million after-tax. We did not incur pension settlement expense in 2014.

Losses from Technology were $93 million in 2014, compared with losses of $6 million in 2013. The reduction in earnings primarily resulted from lower licensing revenues and higher research and development expenses.

## CAPITAL RESOURCES AND LIQUIDITY

### Financial Indicators

| | | Millions of Dollars Except as Indicated | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| Net cash provided by continuing operating activities | $ | **7,572** | 16,412 | 15,856 |
| Net cash provided by discontinued operations | | **-** | 157 | 285 |
| Cash and cash equivalents | | **2,368** | 5,062 | 6,246 |
| Short-term debt | | **1,427** | 182 | 589 |
| Total debt | | **24,880** | 22,565 | 21,662 |
| Total equity | | **40,082** | 52,273 | 52,492 |
| Percent of total debt to capital* | | **38 %** | 30 | 29 |
| Percent of floating-rate debt to total debt** | | **7 %** | 5 | 8 |

**Capital includes total debt and total equity.*
***Includes effect of interest rate swaps in 2013.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources. Cash generated from continuing operating activities is the primary source of funding. In addition, during 2015 we received $1,952 million in proceeds from asset sales and issued $2,498 million of new fixed and floating rate notes. The primary uses of our available cash were $10,050 million to support our ongoing capital expenditures and investments program; $3,664 million to pay dividends on our common stock; and $103 million to repay debt. During 2015, cash and cash equivalents decreased by $2,694 million, to $2,368 million.

In addition to cash flows from operating activities and proceeds from asset sales, we rely on our commercial paper and credit facility programs and our shelf registration statement to support our short- and long-term liquidity requirements. We believe current cash balances and cash generated by operations, together with access to external sources of funds as described below in the “Significant Sources of Capital” section, will be sufficient to meet our funding requirements in the near and long term, including our capital spending program, dividend payments and required debt payments.

### Significant Sources of Capital

*Operating Activities*
During 2015, cash provided by continuing operating activities was $7,572 million, a 54 percent decrease from 2014. The decrease was primarily due to lower prices across all commodities and the absence of the $1.3 billion distribution from FCCL in the first quarter of 2014, partly offset by year-over-year production growth. The distribution from FCCL resulted from our $2.8 billion prepayment of the remaining joint venture acquisition obligation in 2013, which substantially increased the financial flexibility of our 50 percent owned FCCL Partnership. We do not expect this individually significant distribution to recur in the future under current economic conditions. During 2014, cash provided by continuing operations was $16,412 million, compared with $15,856 million in 2013.

While the stability of our cash flows from operating activities benefits from geographic diversity, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, bitumen, natural gas, LNG and natural gas liquids. Prices and margins in our industry have historically been volatile and are driven by market conditions over which we have no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

The level of absolute production volumes, as well as product and location mix, impacts our cash flows. Our 2015 production averaged 1,589 MBOED. We expect 2016 production to be flat with 2015 production of 1,525 MBOED, which excludes 64 MBOED for the full-year impact of completed dispositions. Future production is subject to numerous uncertainties, including, among others, the volatile crude oil and natural gas price environment, which may impact investment decisions; the effects of price changes on production sharing and variable-royalty contracts; acquisition and disposition of fields; field production decline rates; new technologies; operating efficiencies; timing of startups and major turnarounds; political instability; weather-related disruptions; and the addition of proved reserves through exploratory success and their timely and cost-effective development. While we actively manage these factors, production levels can cause variability in cash flows, although generally this variability has not been as significant as that caused by commodity prices.

To maintain or grow our production volumes, we must continue to add to our proved reserve base. Our total reserve replacement in 2015 was negative 19 percent. Excluding the impact of sales and purchases, the organic reserve replacement was 10 percent of 2015 production. Over the five-year period ended December 31, 2015, our reserve replacement was 96 percent (including 54 percent from consolidated operations) reflecting the impact of asset dispositions. Excluding these items and purchases, our five-year organic reserve replacement was 117 percent. The total reserve replacement amount above is based on the sum of our net additions (revisions, improved recovery, purchases, extensions and discoveries, and sales) divided by our production, as shown in our reserve table disclosures. In the event we undertake any cash conservation efforts, our reserve replacement efforts could be delayed thus limiting our ability to replace depleted reserves. For additional information about our 2016 capital budget, see the “2016 Capital Budget” section within “Capital Resources and Liquidity” and for additional information on proved reserves, including both developed and undeveloped reserves, see the “Oil and Gas Operations” section of this report.

As discussed in the “Critical Accounting Estimates” section, engineering estimates of proved reserves are imprecise; therefore, each year reserves may be revised upward or downward due to the impact of changes in commodity prices or as more technical data becomes available on reservoirs. In 2015, revisions decreased reserves, while in 2014 and 2013, revisions increased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future.

*Investing Activities*
Proceeds from asset sales in 2015 were $2.0 billion, primarily from the sales of certain western Canadian properties; producing properties in East Texas and North Louisiana and in South Texas; a certain pipeline and gathering assets in South Texas; and our 50 percent equity method investment in the Russian joint venture, Polar Lights Company. This compares with proceeds of $1.6 billion in 2014, primarily from the sale of our Nigeria upstream affiliates for net proceeds of $1.4 billion, after customary adjustments, inclusive of deposits previously received. For additional information, see Note 3—Discontinued Operations, and Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements. We continue to optimize our asset portfolio by focusing on assets which offer the highest returns and growth potential, while selling non-core assets. For additional information regarding marketing activities, see the “Outlook” section within Management’s Discussion and Analysis.

In May 2015, we liquidated certain deferred compensation investments for proceeds of $267 million, which is included in the “Other” line within “Cash Flows From Investing Activities” on our consolidated statement of cash flows. We do not expect further material liquidations associated with deferred compensation investments. For additional information, see Note 15—Fair Value Measurement, in the Notes to Consolidated Financial Statements. Cash flows from investing activities in 2014 were impacted by the $454 million receipt of the Freeport LNG loan repayment.

*Commercial Paper and Credit Facilities*
During 2015, we had a revolving credit facility totaling $7.0 billion expiring in June 2019. Our revolving credit facility may be used for direct bank borrowings, for the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper programs. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips or any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the United States. The agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

Our primary funding source for short-term working capital needs is the ConocoPhillips $6.1 billion commercial paper program. Commercial paper maturities are generally limited to 90 days. We also have the ConocoPhillips Qatar Funding Ltd. $900 million commercial paper program, which is used to fund commitments relating to QG3. At both December 31, 2015 and 2014, we had no direct borrowings or letters of credit issued under the revolving credit facility. Under the ConocoPhillips Qatar Funding Ltd. commercial paper programs, $803 million of commercial paper was outstanding at December 31, 2015, compared with $860 million at December 31, 2014. Since we had $803 million of commercial paper outstanding and had issued no letters of credit, we had access to $6.2 billion in borrowing capacity under our revolving credit facility at December 31, 2015.

In August 2015, Moody's Investors Service downgraded our senior long-term debt ratings to "A2" from "A1", with a stable outlook. In February 2016, Standard and Poor's placed our long-term and short-term corporate credit ratings on CreditWatch with Negative Implications. Due to the recent significant decline in commodity prices and the expectation these prices could remain depressed in the near future, the major ratings agencies have indicated they will be conducting a review of the oil and gas industry. During the first quarter of 2016, the credit ratings for several companies in the oil and gas industry were downgraded, and we expect further downgrades may broadly impact the industry during the first half of 2016. We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity, in the event of a further downgrade of our credit rating. If our credit rating were to deteriorate to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our revolving credit facility.

Certain of our project-related contracts and derivative instruments contain provisions requiring us to post collateral. Many of these contracts and instruments permit us to post either cash or letters of credit as collateral. At December 31, 2015 and December 31, 2014, we had direct bank letters of credit of $340 million and $802 million, respectively, which secured performance obligations related to various purchase commitments incident to the ordinary conduct of business.

*Shelf Registration*
We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

**Off-Balance Sheet Arrangements**

As part of our normal ongoing business operations and consistent with normal industry practice, we enter into numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements.

For information about guarantees, see Note 12—Guarantees, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

**Capital Requirements**

For information about our capital expenditures and investments, see the "Capital Expenditures" section.

Our debt balance at December 31, 2015, was $24.9 billion, an increase of $2.3 billion from the balance at December 31, 2014, primarily as a result of the May 2015 issuance of $2.5 billion in new fixed and floating rate notes. Our short-term debt balance at December 31, 2015, increased $1.2 billion compared with

December 31, 2014, primarily as a result of the timing of scheduled maturities. We expect to pursue financing options in 2016 to provide additional capital to finance our operations and to partially refinance some of our long-term borrowings, which may include offerings of additional notes from time to time depending on market conditions. For more information, see Note 11—Debt, in the Notes to Consolidated Financial Statements.

We were obligated to contribute $7.5 billion, plus interest, over a 10-year period that began in 2007, to our 50 percent owned FCCL Partnership. In December 2013, we paid the remaining balance of the obligation, which totaled $2,810 million and is included in the "Other" line in the financing activities section of our consolidated statement of cash flows.

In October 2015, we announced a dividend of 74 cents per share. The dividend was paid December 1, 2015, to stockholders of record at the close of business on October 19, 2015. On February 4, 2016, we announced a reduction in the quarterly dividend to 25 cents per share, compared with the previous quarterly dividend of 74 cents per share. We believe this effort will allow us to preserve our balance sheet strength and provide financial flexibility through the current downturn. The dividend will be paid March 1, 2016, to stockholders of record at the close of business on February 16, 2016.

**Contractual Obligations**

The following table summarizes our aggregate contractual fixed and variable obligations of our continuing operations as of December 31, 2015:

| | Millions of Dollars | | | | |
|---|---|---|---|---|---|
| | Payments Due by Period | | | | |
| | Total | Up to 1 Year | Years 2–3 | Years 4–5 | After 5 Years |
| Debt obligations (a) | $ 24,062 | 1,365 | 2,841 | 4,484 | 15,372 |
| Capital lease obligations (b) | 818 | 62 | 99 | 106 | 551 |
| Total debt | 24,880 | 1,427 | 2,940 | 4,590 | 15,923 |
| Interest on debt and other obligations | 15,120 | 1,185 | 2,209 | 1,792 | 9,934 |
| Operating lease obligations (c) | 2,157 | 671 | 575 | 530 | 381 |
| Purchase obligations (d) | 12,359 | 5,043 | 2,040 | 1,324 | 3,952 |
| Other long-term liabilities | | | | | |
| Pension and postretirement benefit contributions (e) | 1,999 | 414 | 892 | 693 | - |
| Asset retirement obligations (f) | 9,911 | 553 | 1,101 | 1,006 | 7,251 |
| Accrued environmental costs (g) | 258 | 39 | 51 | 35 | 133 |
| Unrecognized tax benefits (h) | 46 | 46 | (h) | (h) | (h) |
| Total | $ 66,730 | 9,378 | 9,808 | 9,970 | 37,574 |

(a) Includes $284 million of net unamortized premiums, discounts and debt issuance costs. See Note 11—Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) Capital lease obligations are presented on a discounted basis.

(c) Operating lease obligations are presented on an undiscounted basis.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms, presented on an undiscounted basis. Does not include purchase commitments for jointly owned fields and facilities where we are not the operator.

The majority of the purchase obligations are market-based contracts related to our commodity business. Product purchase commitments with third parties totaled $3,986 million.

Purchase obligations of $6,664 million are related to agreements to access and utilize the capacity of third-party equipment and facilities, including pipelines and LNG and product terminals, to transport, process, treat and store commodities. The remainder is primarily our net share of purchase commitments for materials and services for jointly owned fields and facilities where we are the operator.

(e) Represents contributions to qualified and nonqualified pension and postretirement benefit plans for the years 2016 through 2020. For additional information related to expected benefit payments subsequent to 2020, see Note 18—Employee Benefit Plans, in the Notes to Consolidated Financial Statements.

(f) Represents estimated discounted costs to retire and remove long-lived assets at the end of their operations.

(g) Represents estimated costs for accrued environmental expenditures presented on a discounted basis for costs acquired in various business combinations and an undiscounted basis for all other accrued environmental costs.

(h) Excludes unrecognized tax benefits of $413 million because the ultimate disposition and timing of any payments to be made with regard to such amounts are not reasonably estimable. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

**Capital Expenditures**

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| Alaska | $ | **1,352** | 1,564 | 1,140 |
| Lower 48 | | **3,765** | 6,054 | 5,210 |
| Canada | | **1,255** | 2,340 | 2,232 |
| Europe and North Africa | | **1,573** | 2,540 | 3,126 |
| Asia Pacific and Middle East | | **1,812** | 3,877 | 3,382 |
| Other International | | **173** | 520 | 265 |
| Corporate and Other | | **120** | 190 | 182 |
| Capital expenditures and investments from continuing operations | | **10,050** | 17,085 | 15,537 |
| Discontinued operations in Kashagan, Nigeria and Algeria | | **-** | 59 | 609 |
| Joint venture acquisition obligation (principal)—Canada* | | **-** | - | 772 |
| Capital Program | $ | **10,050** | 17,144 | 16,918 |

**Excludes $2,810 million prepayment in the fourth quarter of 2013.*

Working capital changes associated with investing activities increased cash used in investing activities by $968 million for the year ended December 31, 2015, compared with a decrease of $180 million for the corresponding period of 2014, and an increase of $55 million for the corresponding period of 2013. The increase in cash used in investing activities as of December 31, 2015, is attributable to reduced capital accruals, as compared with December 31, 2014, from lower activity levels in 2015, primarily in the Lower 48 and Canada.

Our capital expenditures and investments from continuing operations for the three-year period ended December 31, 2015, totaled $42.7 billion. The 2015 expenditures supported key exploration and developments, primarily:

- Oil and natural gas development and exploration activities in the Lower 48, including Eagle Ford, Bakken, and the Permian Basin.
- Major project expenditures associated with the APLNG joint venture in Australia.
- Oil sands development, notably at Surmont 2, and ongoing liquids-rich plays in Canada.
- Alaska activities related to development in the Greater Kuparuk Area, Greater Prudhoe Area and the Western North Slope.
- In Europe, development activities in the Greater Ekofisk, Aasta Hansteen, Clair Ridge, Jasmine and Greater Britannia areas, and exploration and appraisal activities in the Jasmine and Greater Clair areas.
- Exploration and appraisal drilling in deepwater Gulf of Mexico.
- Continued development in Malaysia, Indonesia, China, Timor-Leste and offshore Australia, and exploration and appraisal activity in Malaysia, Indonesia, China and offshore Australia.
- Exploration activities in Angola and Senegal.

2016 CAPITAL BUDGET

In anticipation of ongoing weak commodity prices in 2016, our capital budget was reduced in February 2016 from the previously announced $7.7 billion to $6.4 billion, a decrease of 37 percent compared with 2015 capital expenditures of $10.1 billion. The reduction in capital relative to 2015 primarily reflects lower major project spending, deflation capture, deferral of activity and efficiency improvements.

We are planning to allocate approximately:

- 34 percent of our 2016 capital expenditures budget to development drilling programs. These funds will focus predominantly on the Lower 48 unconventionals including the Eagle Ford and Bakken, as well as development drilling in Canada, Alaska, the Greater Ekofisk Area, and in legacy assets within Asia Pacific and Middle East.
- 31 percent of our 2016 capital expenditures budget to major projects. These funds will focus on startup of APLNG Train 2, as well as major projects in Alaska, Europe, Malaysia and China.
- 18 percent of our 2016 capital expenditures budget to exploration and appraisal activity. These funds will primarily target the Gulf of Mexico, Senegal, Nova Scotia, and Alaska.
- 17 percent of our 2016 capital expenditures budget to maintain base production and corporate expenditures.

For information on proved undeveloped reserves and the associated costs to develop these reserves, see the "Oil and Gas Operations" section.

**Contingencies**

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been made against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. With respect to income tax related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. For information on other contingencies, see "Critical Accounting Estimates" and Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

*Legal and Tax Matters*
We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, personal injury, and property damage. Our primary exposures for such matters relate to alleged royalty underpayments on certain federal, state and privately owned properties and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required. See Note 19—Income Taxes, in the Notes to Consolidated Financial Statements, for additional information about income tax related contingencies.

*Environmental*
We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in our industry. The most significant of these environmental laws and regulations include, among others, the:

- U.S. Federal Clean Air Act, which governs air emissions.
- U.S. Federal Clean Water Act, which governs discharges to water bodies.
- European Union Regulation for Registration, Evaluation, Authorization and Restriction of Chemicals (REACH).
- U.S. Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which imposes liability on generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur.
- U.S. Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage and disposal of solid waste.
- U.S. Federal Oil Pollution Act of 1990 (OPA90), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States.
- U.S. Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and response departments.
- U.S. Federal Safe Drinking Water Act, which governs the disposal of wastewater in underground injection wells.
- U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages.
- European Union Trading Directive resulting in European Emissions Trading Scheme.

These laws and their implementing regulations set limits on emissions and, in the case of discharges to water, establish water quality limits. They also, in most cases, require permits in association with new or modified operations. These permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time consuming. In addition, there can be delays associated with notice and comment periods and the agency's processing of the application. Many of the delays associated with the permitting process are beyond the control of the applicant.

Many states and foreign countries where we operate also have, or are developing, similar environmental laws and regulations governing these same types of activities. While similar, in some cases these regulations may impose additional, or more stringent, requirements that can add to the cost and difficulty of marketing or transporting products across state and international borders.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor easily determinable as new standards, such as air emission standards, water quality standards and stricter fuel regulations, continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change, are expected to continue to have an increasing impact on our operations in the United States and in other countries in which we operate. Notable areas of potential impacts include air emission compliance and remediation obligations in the United States and Canada.

An example is the use of hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas otherwise trapped in lower permeability rock formations. A range of local, state, federal or national laws and regulations currently govern hydraulic fracturing operations, with hydraulic fracturing currently prohibited in some jurisdictions. Although hydraulic fracturing has been conducted for many decades, a number of new laws, regulations and permitting requirements are under consideration by the U.S. Environmental Protection Agency (EPA), the U.S. Department of the Interior, and others which could result in increased costs, operating restrictions, operational delays and/or limit the ability to develop oil and natural gas resources. Governmental restrictions on hydraulic fracturing could impact the overall profitability or viability of certain of our oil and natural gas investments. We have adopted operating principles that incorporate established industry standards designed to meet or exceed government requirements. Our practices continually evolve as technology improves and regulations change.

We also are subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations. Such laws and regulations include CERCLA and RCRA and their state equivalents. Longer-term expenditures are subject to considerable uncertainty and may fluctuate significantly.

We occasionally receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2015, there were 14 sites around the United States in which we were identified as a potentially responsible party under CERCLA and comparable state laws.

For most Superfund sites, our potential liability will be significantly less than the total site remediation costs because the percentage of waste attributable to us, versus that attributable to all other potentially responsible parties, is relatively low. Although liability of those potentially responsible is generally joint and several for federal sites and frequently so for state sites, other potentially responsible parties at sites where we are a party typically have had the financial strength to meet their obligations, and where they have not, or where potentially responsible parties could not be located, our share of liability has not increased materially. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or attain a settlement of liability. Actual cleanup costs generally occur after the parties obtain EPA or equivalent state agency approval. There are relatively few sites where we are a major participant, and given the timing and amounts of anticipated expenditures, neither the cost of remediation at those sites nor such costs at all CERCLA sites, in the aggregate, is expected to have a material adverse effect on our competitive or financial condition.

Expensed environmental costs were $485 million in 2015 and are expected to be about $478 million per year in 2016 and 2017. Capitalized environmental costs were $303 million in 2015 and are expected to be about $250 million per year in 2016 and 2017.

Accrued liabilities for remediation activities are not reduced for potential recoveries from insurers or other third parties and are not discounted (except those assumed in a purchase business combination, which we do record on a discounted basis).

Many of these liabilities result from CERCLA, RCRA and similar state or international laws that require us to undertake certain investigative and remedial activities at sites where we conduct, or once conducted, operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites we identified that may require environmental remediation, but which are not currently the subject of CERCLA, RCRA or other agency enforcement activities. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the future, we may incur significant costs under both CERCLA and RCRA.

Remediation activities vary substantially in duration and cost from site to site, depending on the mix of unique site characteristics, evolving remediation technologies, diverse regulatory agencies and enforcement policies, and the presence or absence of potentially liable third parties. Therefore, it is difficult to develop reasonable estimates of future site remediation costs.

At December 31, 2015, our balance sheet included total accrued environmental costs of $258 million, compared with $344 million at December 31, 2014, for remediation activities in the U.S., Canada and the U.K. We expect to incur a substantial amount of these expenditures within the next 30 years.

Notwithstanding any of the foregoing, and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent concerns in our operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, we currently do not expect any material adverse effect upon our results of operations or financial position as a result of compliance with current environmental laws and regulations.

*Climate Change*

There has been a broad range of proposed or promulgated state, national and international laws focusing on greenhouse gas (GHG) reduction. These proposed or promulgated laws apply or could apply in countries where we have interests or may have interests in the future. Laws in this field continue to evolve, and while it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation, such laws, if enacted, could have a material impact on our results of operations and financial condition. Examples of legislation or precursors for possible regulation that do or could affect our operations include:

- European Emissions Trading Scheme (ETS), the program through which many of the European Union (EU) member states are implementing the Kyoto Protocol. Our cost of compliance with the EU ETS in 2015 was approximately $0.4 million (net share pre-tax).
- In Canada during 2015, the Alberta government amended the regulations of the Climate Change and Emissions Act. The regulations now require any existing facility with emissions equal to or greater than 100,000 metric tonnes of carbon dioxide or equivalent per year to reduce its net emissions intensity from its baseline. The reduction is increasing from the current 12 percent in 2015, to 15 percent in 2016 and to 20 percent in 2017. We also incur a carbon tax for emissions from fossil fuel combustion in our British Columbia operations. The total cost of compliance with these regulations in 2015 was approximately $4.7 million.
- The U.S. Supreme Court decision in Massachusetts v. EPA, 549 U.S. 497, 127 S.Ct. 1438 (2007), confirming that the EPA has the authority to regulate carbon dioxide as an "air pollutant" under the Federal Clean Air Act.

- The U.S. EPA's announcement on March 29, 2010 (published as "Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs," 75 Fed. Reg. 17004 (April 2, 2010)), and the EPA's and U.S. Department of Transportation's joint promulgation of a Final Rule on April 1, 2010, that triggers regulation of GHGs under the Clean Air Act, may trigger more climate-based claims for damages, and may result in longer agency review time for development projects.
- The U.S. EPA's announcement on January 14, 2015, outlining a series of steps it plans to take to address methane and smog-forming volatile organic compound emissions from the oil and gas industry. The current U.S. administration has established a goal of reducing the 2012 levels in methane emissions from the oil and gas industry by 40 to 45 percent by 2025.
- Carbon taxes in certain jurisdictions. Our cost of compliance with Norwegian carbon tax legislation in 2015 was approximately $31 million (net share pre-tax).
- The agreement reached in Paris in December 2015 at the 21st Conference of the Parties to the United Nations Framework on Climate Change, setting out a new process for achieving global emission reductions.

In the United States, some additional form of regulation may be forthcoming in the future at the federal and state levels with respect to GHG emissions. Such regulation could take any of several forms that may result in the creation of additional costs in the form of taxes, the restriction of output, investments of capital to maintain compliance with laws and regulations, or required acquisition or trading of emission allowances. We are working to continuously improve operational and energy efficiency through resource and energy conservation throughout our operations.

Compliance with changes in laws and regulations that create a GHG emission trading scheme or GHG reduction policies could significantly increase our costs, reduce demand for fossil energy derived products, impact the cost and availability of capital and increase our exposure to litigation. Such laws and regulations could also increase demand for less carbon intensive energy sources, including natural gas. The ultimate impact on our financial performance, either positive or negative, will depend on a number of factors, including but not limited to:

- Whether and to what extent legislation or regulation is enacted.
- The timing of the introduction of such legislation or regulation.
- The nature of the legislation (such as a cap and trade system or a tax on emissions) or regulation.
- The price placed on GHG emissions (either by the market or through a tax).
- The GHG reductions required.
- The price and availability of offsets.
- The amount and allocation of allowances.
- Technological and scientific developments leading to new products or services.
- Any potential significant physical effects of climate change (such as increased severe weather events, changes in sea levels and changes in temperature).
- Whether, and the extent to which, increased compliance costs are ultimately reflected in the prices of our products and services.

The company has responded by putting in place a corporate Climate Change Action Plan, together with individual business unit climate change management plans in order to undertake actions in four major areas:

- Equipping the company for a low emission world, for example by integrating GHG forecasting and reporting into company procedures; utilizing GHG pricing in planning economics; developing systems to handle GHG market transactions.
- Reducing GHG emissions—In 2014, the company reduced or avoided GHG emissions by approximately 900,000 metric tonnes by carrying out a range of programs across a number of business units.
- Evaluating business opportunities such as the creation of offsets and allowances; carbon capture and storage; the use of low carbon energy and the development of low carbon technologies.
- Engaging externally—The company is a sponsor of MIT's Joint Program on the Science and Policy of Global Change; constructively engages in the development of climate change legislation and regulation; and discloses our progress and performance through the Carbon Disclosure Project and the Dow Jones Sustainability Index.

The company uses an estimated market cost of GHG emissions in the range of $8 to $35 per tonne depending on the timing and country or region to evaluate future opportunities.

**Other**

We have deferred tax assets related to certain accrued liabilities, loss carryforwards and credit carryforwards. Valuation allowances have been established to reduce these deferred tax assets to an amount that will, more likely than not, be realized. Based on our historical taxable income, our expectations for the future, and available tax-planning strategies, management expects the net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as offsets to the tax consequences of future taxable income.

## CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. See Note 1—Accounting Policies, in the Notes to Consolidated Financial Statements, for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent there is a reasonable likelihood materially different amounts would have been reported under different conditions, or if different assumptions had been used. These critical accounting estimates are discussed with the Audit and Finance Committee of the Board of Directors at least annually. We believe the following discussions of critical accounting estimates, along with the discussions of contingencies and of deferred tax asset valuation allowances in this report, address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

### Oil and Gas Accounting

Accounting for oil and gas exploratory activity is subject to special accounting rules unique to the oil and gas industry. The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs. However, leasehold acquisition costs and exploratory well costs are capitalized on the balance sheet pending determination of whether proved oil and gas reserves have been discovered on the prospect.

*Property Acquisition Costs*

For individually significant leaseholds, management periodically assesses for impairment based on exploration and drilling efforts to date. For relatively small individual leasehold acquisition costs, management exercises judgment and determines a percentage probability that the prospect ultimately will fail to find proved oil and gas reserves and pools that leasehold information with others in the geographic area. For prospects in areas with limited, or no, previous exploratory drilling, the percentage probability of ultimate failure is normally judged to be quite high. This judgmental percentage is multiplied by the leasehold acquisition cost, and that product is divided by the contractual period of the leasehold to determine a periodic leasehold impairment charge that is reported in exploration expense.

This judgmental probability percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favorable or unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment amortization expense is adjusted prospectively. At year-end 2015, the book value of the pools of property acquisition costs, that individually are relatively small and thus subject to the above-described periodic leasehold impairment calculation, was $515 million and the accumulated impairment reserve was $191 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 74 percent, and the weighted-average amortization period was approximately three years. If that judgmental percentage were to be raised by 5 percent across all calculations, pre-tax leasehold impairment expense in 2016 would increase by approximately $7 million. At year-end 2015, the remaining $4,501 million of net capitalized unproved property costs consisted primarily of individually significant leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently being drilled, suspended exploratory wells, and capitalized interest. Of this amount, approximately $3 billion is concentrated in 12 major development areas, the majority of which are not expected to move to proved properties in 2016. Management periodically assesses individually significant leaseholds for impairment based on the results of exploration and drilling efforts and the outlook for commercialization.

*Exploratory Costs*

For exploratory wells, drilling costs are temporarily capitalized, or "suspended," on the balance sheet, pending a determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort to justify completion of the find as a producing well.

If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. The accounting notion of "sufficient progress" is a judgmental area, but the accounting rules do prohibit continued capitalization of suspended well costs on the expectation future market conditions will improve or new technologies will be found that would make the development economically profitable. Often, the ability to move into the development phase and record proved reserves is dependent on obtaining permits and government or co-venturer approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as we are actively pursuing such approvals and permits, and believe they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once a determination is made the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and reported in exploration expense.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as a dry hole when it determines the potential field does not warrant further investment in the near term. Criteria utilized in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected development costs, ability to apply existing technology to produce the reserves, fiscal terms, regulations or contract negotiations, and our expected return on investment.

At year-end 2015, total suspended well costs were $1,260 million, compared with $1,299 million at year-end 2014. For additional information on suspended wells, including an aging analysis, see Note 8—Suspended Wells and Other Exploration Expenses, in the Notes to Consolidated Financial Statements.

*Proved Reserves*
Engineering estimates of the quantities of proved reserves are inherently imprecise and represent only approximate amounts because of the judgments involved in developing such information. Reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processing yield factors, installed plant operating capacity and approved operating limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons.

Despite the inherent imprecision in these engineering estimates, accounting rules require disclosure of "proved" reserve estimates due to the importance of these estimates to better understand the perceived value and future cash flows of a company's operations. There are several authoritative guidelines regarding the engineering criteria that must be met before estimated reserves can be designated as "proved." Our geosciences and reservoir engineering organization has policies and procedures in place consistent with these authoritative guidelines. We have trained and experienced internal engineering personnel who estimate our proved reserves held by consolidated companies, as well as our share of equity affiliates.

Proved reserve estimates are adjusted annually in the fourth quarter and during the year if significant changes occur, and take into account recent production and subsurface information about each field. Also, as required by current authoritative guidelines, the estimated future date when an asset will be permanently shut down for economic reasons is based on 12-month average prices and current costs. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Generally, our proved reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to production sharing contracts, reported under the "economic interest" method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. We would expect reserves from these contracts to decrease when product prices rise and increase when prices decline.

The estimation of proved developed reserves also is important to the income statement because the proved developed reserve estimate for a field serves as the denominator in the unit-of-production calculation of the DD&A of the capitalized costs for that asset. At year-end 2015, the net book value of productive properties, plants and equipment (PP&E) subject to a unit-of-production calculation was approximately $58 billion and the DD&A recorded on these assets in 2015 was approximately $8.7 billion. The estimated proved developed reserves for our consolidated operations were 4.6 billion BOE at the end of 2014 and 4.0 billion BOE at the end of 2015. If the estimates of proved reserves used in the unit-of-production calculations had been lower by 10 percent across all calculations, pre-tax DD&A in 2015 would have increased by an estimated $960 million.

**Impairments**

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. If there is an indication the carrying amount of an asset may not be recovered, the asset is monitored by management through an established process where changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted pre-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for exploration and production assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of future production volumes, commodity prices, operating costs and capital decisions, considering all available information at the date of review. Differing assumptions could affect the timing and the amount of an impairment in any period. See Note 9—Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment when there is evidence of a loss in value and annually following updates to corporate planning assumptions. Such evidence of a loss in value might include our inability to recover the carrying amount, the lack of sustained earnings capacity which would justify the current investment amount, or a current fair value less than the investment's carrying amount. When it is determined such a loss in value is other than temporary, an impairment charge is recognized for the difference between the investment's carrying value and its estimated fair value. When determining whether a decline in value is other than temporary, management considers factors such as the length of time and extent of the decline, the investee's financial condition and near-term prospects, and our ability and intention to retain our investment for a period that will be sufficient to allow for any anticipated recovery in the market value of the investment. Since quoted market prices are usually not available, the fair value is typically based on the present value of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate. Differing assumptions could affect the timing and the amount of an impairment of an investment in any period.

**Asset Retirement Obligations and Environmental Costs**

Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at operational sites. Our largest asset removal obligations involve plugging and abandonment of wells, removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska. The fair values of obligations for dismantling and removing these facilities are recorded as a liability and an increase to PP&E at the time of installation of the asset based on estimated discounted costs. Estimating future asset removal costs is difficult. Most of these removal obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. Asset removal technologies and costs, regulatory and other compliance considerations, expenditure timing, and other inputs into valuation of the obligation, including discount and inflation rates, are also subject to change.

Normally, changes in asset removal obligations are reflected in the income statement as increases or decreases to DD&A over the remaining life of the assets. However, for assets at or nearing the end of their operations, as well as previously sold assets for which we retained the asset removal obligation, an increase in the asset removal obligation can result in an immediate charge to earnings, because any increase in PP&E due to the increased obligation would immediately be subject to impairment, due to the low fair value of these properties.

In addition to asset removal obligations, under the above or similar contracts, permits and regulations, we have certain environmental-related projects. These are primarily related to remediation activities required by Canada and various states within the United States at exploration and production sites. Future environmental remediation costs are difficult to estimate because they are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. See Note 10—Asset Retirement Obligations and Accrued Environmental Costs, in the Notes to Consolidated Financial Statements, for additional information.

**Projected Benefit Obligations**

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations and company contribution requirements. For Employee Retirement Income Security Act-governed pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into the plans. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all vested benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Projected benefit obligations are particularly sensitive to the discount rate assumption. A 1 percent decrease in the discount rate assumption would increase projected benefit obligations by $1,100 million. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate assumption would increase annual benefit expense by $100 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $70 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans. We are also exposed to the possibility that lump sum retirement benefits taken from pension plans during the year could exceed the total of service and interest components of annual pension expense and trigger accelerated recognition of a portion of unrecognized net actuarial losses and gains.  These benefit payments are based on decisions by plan participants and are therefore difficult to predict.  In the event there is a significant reduction in the expected years of future service of present employees or elimination for a significant number of employees the accrual of defined benefits for some or all of their future services, we could recognize a curtailment gain or loss.  See Note 18—Employee Benefit Plans, in the Notes to Consolidated Financial Statements, for additional information.

**Contingencies**

A number of claims and lawsuits are made against the company arising in the ordinary course of business. Management exercises judgment related to accounting and disclosure of these claims which includes losses, damages, and underpayments associated with environmental remediation, tax, contracts, and other legal disputes.  As we learn new facts concerning contingences, we reassess our position both with respect to amounts recognized and disclosed considering changes to the probability of additional losses and potential exposure.  However, actual losses can and do vary from estimates for a variety of reasons including legal, arbitration, or other third party decisions; settlement discussions; evaluation of scope of damages; interpretation of regulatory or contractual terms; expected timing of future actions; and proportion of liability shared with other responsible parties.  Estimated future costs related to contingencies are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.  For additional information on contingent liabilities, see the “Contingencies” section within “Capital Resources and Liquidity.”

**CAUTIONARY STATEMENT FOR THE PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995**

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans, and objectives of management for future operations, are forward-looking statements. Examples of forward-looking statements contained in this report include our expected production growth in 2016 and outlook on the business environment generally, our expected capital budget and capital expenditures, and discussions concerning future dividends. You can often identify our forward-looking statements by 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.

We based the forward-looking statements on our current expectations, estimates and projections about ourselves and the industries in which we operate in general. We caution you these statements are not guarantees of future performance as they involve assumptions that, while made in good faith, may prove to be incorrect, and involve risks and uncertainties we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including, but not limited to, the following:

- Fluctuations in crude oil, bitumen, natural gas, LNG and natural gas liquids prices, including a prolonged decline in these prices relative to historical or future expected levels.
- The impact of recent, significant declines in prices for crude oil, bitumen, natural gas, LNG and natural gas liquids, which may result in recognition of impairment costs on our long-lived assets, leaseholds and nonconsolidated equity investments.
- Potential failures or delays in achieving expected reserve or production levels from existing and future oil and gas developments due to operating hazards, drilling risks and the inherent uncertainties in predicting reserves and reservoir performance.
- Inability to maintain reserves replacement rates consistent with prior periods, whether as a result of the recent, significant declines in commodity prices or otherwise.
- Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.
- Unexpected changes in costs or technical requirements for constructing, modifying or operating exploration and production facilities.
- Legislative and regulatory initiatives addressing environmental concerns, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, bitumen, natural gas, LNG and natural gas liquids.
- Inability to timely obtain or maintain permits, including those necessary for drilling and/or development, construction of LNG terminals or regasification facilities; comply with government regulations; or make capital expenditures required to maintain compliance.
- Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future exploration and production and LNG development.
- Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events, terrorism, cyber attacks or infrastructure constraints or disruptions.
- International monetary conditions and exchange controls, and changes in foreign currency exchange rates.
- Substantial investment or reduced demand for products as a result of existing or future environmental rules and regulations, use of competing energy sources or the development of alternative energy sources.

- Liability for remedial actions, including removal and reclamation obligations, under environmental regulations.
- Liability resulting from litigation.
- General domestic and international economic and political developments, including armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, bitumen, natural gas, LNG and natural gas liquids pricing, regulation or taxation; other political, economic or diplomatic developments; and international monetary fluctuations.
- Volatility in the commodity futures markets.
- Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business.
- Competition in the oil and gas exploration and production industry.
- Limited access to capital or significantly higher cost of capital related to illiquidity or uncertainty in the domestic or international financial markets.
- Delays in, or our inability to, execute asset dispositions.
- Inability to obtain economical financing for development, construction or modification of facilities and general corporate purposes.
- The operation and financing of our joint ventures.
- The ability of our customers and other contractual counterparties to satisfy their obligations to us.
- Our inability to realize anticipated cost savings and expenditure reductions.
- The factors generally described in Item 1A—Risk Factors in this report.

## Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

### Financial Instrument Market Risk

We and certain of our subsidiaries hold and issue derivative contracts and financial instruments that expose our cash flows or earnings to changes in commodity prices, foreign currency exchange rates or interest rates. We may use financial and commodity-based derivative contracts to manage the risks produced by changes in the prices of natural gas, crude oil and related products; fluctuations in interest rates and foreign currency exchange rates; or to capture market opportunities.

Our use of derivative instruments is governed by an "Authority Limitations" document approved by our Board of Directors that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity. The Authority Limitations document also establishes the Value at Risk (VaR) limits for the company, and compliance with these limits is monitored daily. The Chief Financial Officer monitors risks resulting from foreign currency exchange rates and interest rates and reports to the Chief Executive Officer. The Executive Vice President of Commercial, Business Development and Corporate Planning monitors commodity price risk and also reports to the Chief Executive Officer. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, and monitors risks.

*Commodity Price Risk*

Our Commercial organization uses futures, forwards, swaps and options in various markets to accomplish the following objectives:

- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas consumers, to floating market prices.
- Enable us to use market knowledge to capture opportunities such as moving physical commodities to more profitable locations and storing commodities to capture seasonal or time premiums. We may use derivatives to optimize these activities.

We use a VaR model to estimate the loss in fair value that could potentially result on a single day from the effect of adverse changes in market conditions on the derivative financial instruments and derivative commodity instruments we hold or issue, including commodity purchases and sales contracts recorded on the balance sheet at December 31, 2015, as derivative instruments. Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes at December 31, 2015 and 2014, was immaterial to our consolidated cash flows and net income attributable to ConocoPhillips. The VaR for instruments held for purposes other than trading at December 31, 2015 and 2014, was also immaterial to our consolidated cash flows and net income attributable to ConocoPhillips.

*Interest Rate Risk*

The following table provides information about our financial instruments that are sensitive to changes in U.S. interest rates. The debt portion of the table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on effective rates at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. The fair value of the fixed-rate financial instruments is estimated based on quoted market prices.

| Expected Maturity Date | Millions of Dollars Except as Indicated | | | | | |
|---|---|---|---|---|---|---|
| | Debt | | | | | |
| | | Fixed Rate Maturity | Average Interest Rate | | Floating Rate Maturity | Average Interest Rate |
| **Year-End 2015** | | | | | | |
| 2016 | **$** | **1,250** | **5.63 %** | **$** | **108** | **0.35 %** |
| 2017 | | **1,024** | **1.03** | | **-** | **-** |
| 2018 | | **1,547** | **3.68** | | **250** | **0.69** |
| 2019 | | **2,250** | **5.75** | | **695** | **0.35** |
| 2020 | | **1,500** | **4.73** | | **-** | **-** |
| Remaining years | | **14,371** | **5.72** | | **783** | **0.81** |
| Total | **$** | **21,942** | | **$** | **1,836** | |
| Fair value | **$** | **22,949** | | **$** | **1,836** | |
| Year-End 2014 | | | | | | |
| 2015 | $ | - | - % | $ | 107 | 0.18 % |
| 2016 | | 1,273 | 5.52 | | - | - |
| 2017 | | 1,001 | 1.06 | | - | - |
| 2018 | | 797 | 5.74 | | - | - |
| 2019 | | 2,250 | 5.75 | | 753 | 0.18 |
| Remaining years | | 14,871 | 5.81 | | 283 | 0.04 |
| Total | $ | 20,192 | | $ | 1,143 | |
| Fair value | $ | 24,048 | | $ | 1,143 | |

*Foreign Currency Exchange Risk*

We have foreign currency exchange rate risk resulting from international operations. We do not comprehensively hedge the exposure to currency exchange rate changes although we may choose to selectively hedge certain foreign currency exchange rate exposures, such as firm commitments for capital projects or local currency tax payments, dividends and cash returns from net investments in foreign affiliates to be remitted within the coming year.

At December 31, 2015 and 2014, we held foreign currency exchange forwards hedging cross-border commercial activity and foreign currency exchange swaps for purposes of mitigating our cash-related exposures. Although these forwards and swaps hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting. As a result, the change in the fair value of these foreign currency exchange derivatives is recorded directly in earnings. Since the gain or loss on the swaps is offset by the gain or loss from remeasuring the related cash balances, and since our aggregate position in the forwards was not material, there would be no material impact to our income from an adverse hypothetical 10 percent change in the December 31, 2015, or 2014, exchange rates. The notional and fair market values of these positions at December 31, 2015 and 2014, were as follows:

| Foreign Currency Exchange Derivatives | In Millions | | | | |
|---|---|---|---|---|---|
| | | Notional* | | Fair Market Value** | |
| | | **2015** | 2014 | **2015** | 2014 |
| Sell U.S. dollar, buy British pound | USD | **200** | - | **(3)** | - |
| Sell U.S. dollar, buy Canadian dollar | USD | **-** | 7 | **-** | (1) |
| Sell U.S. dollar, buy Norwegian krone | USD | **147** | - | **(2)** | - |
| Buy U.S. dollar, sell Norwegian krone | USD | **-** | 44 | **-** | - |
| Buy U.S. dollar, sell Canadian dollar | USD | **20** | - | **2** | - |
| Buy British pound, sell Canadian dollar | GBP | **564** | - | **44** | - |
| Buy British pound, sell euro | GBP | **3** | 20 | **(1)** | 1 |

**Denominated in U.S. dollars (USD) and British pound (GBP).*
***Denominated in U.S. dollars.*

For additional information about our use of derivative instruments, see Note 14—Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

## Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### CONOCOPHILLIPS

### INDEX TO FINANCIAL STATEMENTS

## Report of Management

Management prepared, and is responsible for, the consolidated financial statements and the other information appearing in this annual report. The consolidated financial statements present fairly the company's financial position, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its consolidated financial statements, the company includes amounts that are based on estimates and judgments management believes are reasonable under the circumstances. The company's financial statements have been audited by Ernst & Young LLP, an independent registered public accounting firm appointed by the Audit and Finance Committee of the Board of Directors and ratified by stockholders. Management has made available to Ernst & Young LLP all of the company's financial records and related data, as well as the minutes of stockholders' and directors' meetings.

**Assessment of Internal Control Over Financial Reporting**

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. ConocoPhillips' internal control system was designed to provide reasonable assurance to the company's management and directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2015. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework (2013)*. Based on our assessment, we believe the company's internal control over financial reporting was effective as of December 31, 2015.

Ernst & Young LLP has issued an audit report on the company's internal control over financial reporting as of December 31, 2015, and their report is included herein.

/s/ Ryan M. Lance

**Ryan M. Lance**
Chairman and
Chief Executive Officer

/s/ Jeff W. Sheets

**Jeff W. Sheets**
Executive Vice President, Finance
and Chief Financial Officer

February 23, 2016

## Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
ConocoPhillips

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the related condensed consolidating financial information listed in the Index at Item 8 and financial statement schedule listed in Item 15(a). These financial statements, condensed consolidating financial information, and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements, condensed consolidating financial information, and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of ConocoPhillips at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related condensed consolidating financial information and financial statement schedule, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), ConocoPhillips' internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 23, 2016, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 23, 2016

## Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
ConocoPhillips

We have audited ConocoPhillips' internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). ConocoPhillips' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included under the heading "Assessment of Internal Control Over Financial Reporting" in the accompanying "Report of Management." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe our audit provides a reasonable basis for our opinion.

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

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

In our opinion, ConocoPhillips maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2015 consolidated financial statements of ConocoPhillips and our report dated February 23, 2016, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 23, 2016

Years Ended December 31

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| **Revenues and Other Income** | | | | |
| Sales and other operating revenues | $ | **29,564** | 52,524 | 54,413 |
| Equity in earnings of affiliates | | **655** | 2,529 | 2,219 |
| Gain on dispositions | | **591** | 98 | 1,242 |
| Other income | | **125** | 366 | 374 |
| Total Revenues and Other Income | | **30,935** | 55,517 | 58,248 |
| **Costs and Expenses** | | | | |
| Purchased commodities | | **12,426** | 22,099 | 22,643 |
| Production and operating expenses | | **7,016** | 8,909 | 7,238 |
| Selling, general and administrative expenses | | **953** | 735 | 854 |
| Exploration expenses | | **4,192** | 2,045 | 1,232 |
| Depreciation, depletion and amortization | | **9,113** | 8,329 | 7,434 |
| Impairments | | **2,245** | 856 | 529 |
| Taxes other than income taxes | | **901** | 2,088 | 2,884 |
| Accretion on discounted liabilities | | **483** | 484 | 434 |
| Interest and debt expense | | **920** | 648 | 612 |
| Foreign currency transaction gains | | **(75)** | (66) | (58) |
| Total Costs and Expenses | | **38,174** | 46,127 | 43,802 |
| Income (loss) from continuing operations before income taxes | | **(7,239)** | 9,390 | 14,446 |
| Provision (benefit) for income taxes | | **(2,868)** | 3,583 | 6,409 |
| **Income (Loss) From Continuing Operations** | | **(4,371)** | 5,807 | 8,037 |
| Income from discontinued operations* | | **-** | 1,131 | 1,178 |
| Net income (loss) | | **(4,371)** | 6,938 | 9,215 |
| Less: net income attributable to noncontrolling interests | | **(57)** | (69) | (59) |
| **Net Income (Loss) Attributable to ConocoPhillips** | $ | **(4,428)** | 6,869 | 9,156 |
| **Amounts Attributable to ConocoPhillips Common Shareholders:** | | | | |
| Income (loss) from continuing operations | $ | **(4,428)** | 5,738 | 7,978 |
| Income from discontinued operations* | | **-** | 1,131 | 1,178 |
| Net Income (Loss) | $ | **(4,428)** | 6,869 | 9,156 |
| **Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock** *(dollars)* | | | | |
| Basic | | | | |
| Continuing operations | $ | **(3.58)** | 4.63 | 6.47 |
| Discontinued operations | | **-** | 0.91 | 0.96 |
| Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock | $ | **(3.58)** | 5.54 | 7.43 |
| Diluted | | | | |
| Continuing operations | $ | **(3.58)** | 4.60 | 6.43 |
| Discontinued operations | | **-** | 0.91 | 0.95 |
| Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock | $ | **(3.58)** | 5.51 | 7.38 |
| **Dividends Paid Per Share of Common Stock** *(dollars)* | $ | **2.94** | 2.84 | 2.70 |
| **Average Common Shares Outstanding** *(in thousands)* | | | | |
| Basic | | **1,241,919** | 1,237,325 | 1,230,963 |
| Diluted | | **1,241,919** | 1,245,863 | 1,239,803 |
| **Net of provision for income taxes on discontinued operations of:* | *$* | *-* | *16* | *283* |

*See Notes to Consolidated Financial Statements.*

## Consolidated Statement of Comprehensive Income **ConocoPhillips**

| Years Ended December 31 | | Millions of Dollars | |
|---|---|---|---|
| | **2015** | 2014 | 2013 |
| **Net Income (Loss)** | **$ (4,371)** | 6,938 | 9,215 |
| Other comprehensive income (loss) | | | |
| Defined benefit plans | | | |
| Prior service credit (cost) arising during the period | **301** | (3) | 1 |
| Reclassification adjustment for amortization of prior service credit included in net income | **(19)** | (6) | (5) |
| Net change | **282** | (9) | (4) |
| Net actuarial gain (loss) arising during the period | **592** | (840) | 688 |
| Reclassification adjustment for amortization of net actuarial losses included in net income | **403** | 131 | 294 |
| Net change | **995** | (709) | 982 |
| Nonsponsored plans* | **1** | - | 10 |
| Income taxes on defined benefit plans | **(460)** | 281 | (387) |
| Defined benefit plans, net of tax | **818** | (437) | 601 |
| Foreign currency translation adjustments | **(5,199)** | (3,539) | (2,705) |
| Reclassification adjustment for gain included in net income | **-** | - | (4) |
| Income taxes on foreign currency translation adjustments | **36** | 72 | 23 |
| Foreign currency translation adjustments, net of tax | **(5,163)** | (3,467) | (2,686) |
| **Other Comprehensive Income (Loss), Net of Tax** | **(4,345)** | (3,904) | (2,085) |
| **Comprehensive Income (Loss)** | **(8,716)** | 3,034 | 7,130 |
| Less: comprehensive income attributable to noncontrolling interests | **(57)** | (69) | (59) |
| **Comprehensive Income (Loss) Attributable to ConocoPhillips** | **$ (8,773)** | 2,965 | 7,071 |

**Plans for which ConocoPhillips is not the primary obligor—primarily those administered by equity affiliates.*
*See Notes to Consolidated Financial Statements.*

## Consolidated Balance Sheet **ConocoPhillips**

| At December 31 | | Millions of Dollars | |
|---|---|---|---|
| | | **2015** | 2014 |
| **Assets** | | | |
| Cash and cash equivalents | $ | **2,368** | 5,062 |
| Accounts and notes receivable (net of allowance of $7 million in 2015 and $5 million in 2014) | | **4,314** | 6,675 |
| Accounts and notes receivable—related parties | | **200** | 132 |
| Inventories | | **1,124** | 1,331 |
| Prepaid expenses and other current assets | | **783** | 1,868 |
| Total Current Assets | | **8,789** | 15,068 |
| Investments and long-term receivables | | **20,490** | 24,335 |
| Loans and advances—related parties | | **696** | 804 |
| Net properties, plants and equipment (net of accumulated depreciation, depletion and amortization of $70,413 million in 2015 and $70,786 million in 2014) | | **66,446** | 75,444 |
| Other assets | | **1,063** | 888 |
| Total Assets | $ | **97,484** | 116,539 |
| **Liabilities** | | | |
| Accounts payable | $ | **4,895** | 7,982 |
| Accounts payable—related parties | | **38** | 44 |
| Short-term debt | | **1,427** | 182 |
| Accrued income and other taxes | | **499** | 1,051 |
| Employee benefit obligations | | **887** | 878 |
| Other accruals | | **1,510** | 1,400 |
| Total Current Liabilities | | **9,256** | 11,537 |
| Long-term debt | | **23,453** | 22,383 |
| Asset retirement obligations and accrued environmental costs | | **9,580** | 10,647 |
| Deferred income taxes | | **10,999** | 15,070 |
| Employee benefit obligations | | **2,286** | 2,964 |
| Other liabilities and deferred credits | | **1,828** | 1,665 |
| Total Liabilities | | **57,402** | 64,266 |
| **Equity** | | | |
| Common stock (2,500,000,000 shares authorized at $.01 par value) | | | |
| Issued (2015—1,778,226,388 shares; 2014—1,773,583,368) | | | |
| Par value | | **18** | 18 |
| Capital in excess of par | | **46,357** | 46,071 |
| Treasury stock (at cost: 2015—542,230,673; 2014—542,230,673) | | **(36,780)** | (36,780) |
| Accumulated other comprehensive loss | | **(6,247)** | (1,902) |
| Retained earnings | | **36,414** | 44,504 |
| Total Common Stockholders' Equity | | **39,762** | 51,911 |
| Noncontrolling interests | | **320** | 362 |
| Total Equity | | **40,082** | 52,273 |
| Total Liabilities and Equity | $ | **97,484** | 116,539 |

*See Notes to Consolidated Financial Statements.*

| **Consolidated Statement of Cash Flows** | | | **ConocoPhillips** |
|---|---|---|---|
| Years Ended December 31 | Millions of Dollars | | |
| | **2015** | 2014* | 2013* |
| **Cash Flows From Operating Activities** | | | |
| Net income (loss) | **$ (4,371)** | 6,938 | 9,215 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities | | | |
| Depreciation, depletion and amortization | **9,113** | 8,329 | 7,434 |
| Impairments | **2,245** | 856 | 529 |
| Dry hole costs and leasehold impairments | **3,065** | 1,166 | 443 |
| Accretion on discounted liabilities | **483** | 484 | 434 |
| Deferred taxes | **(2,772)** | 709 | 1,311 |
| Undistributed equity earnings | **101** | 77 | (822) |
| Gain on dispositions | **(591)** | (98) | (1,242) |
| Income from discontinued operations | **-** | (1,131) | (1,178) |
| Other | **321** | (233) | (371) |
| Working capital adjustments | | | |
| Decrease in accounts and notes receivable | **1,810** | 1,227 | 744 |
| Decrease (increase) in inventories | **166** | (193) | (278) |
| Decrease (increase) in prepaid expenses and other current assets | **239** | (190) | (83) |
| Increase (decrease) in accounts payable | **(1,647)** | (963) | 238 |
| Decrease in taxes and other accruals | **(590)** | (566) | (518) |
| Net cash provided by continuing operating activities | **7,572** | 16,412 | 15,856 |
| Net cash provided by discontinued operations | **-** | 157 | 285 |
| Net Cash Provided by Operating Activities | **7,572** | 16,569 | 16,141 |
| | | | |
| **Cash Flows From Investing Activities** | | | |
| Capital expenditures and investments | **(10,050)** | (17,085) | (15,537) |
| Working capital changes associated with investing activities | **(968)** | 180 | (55) |
| Proceeds from asset dispositions | **1,952** | 1,603 | 10,220 |
| Net sales (purchases) of short-term investments | **-** | 253 | (263) |
| Collection of advances/loans—related parties | **105** | 603 | 145 |
| Other | **306** | (446) | (212) |
| Net cash used in continuing investing activities | **(8,655)** | (14,892) | (5,702) |
| Net cash used in discontinued operations | **-** | (73) | (603) |
| Net Cash Used in Investing Activities | **(8,655)** | (14,965) | (6,305) |
| | | | |
| **Cash Flows From Financing Activities** | | | |
| Issuance of debt | **2,498** | 2,994 | - |
| Repayment of debt | **(103)** | (2,014) | (946) |
| Change in restricted cash | **-** | - | 748 |
| Issuance of company common stock | **(82)** | 35 | 20 |
| Dividends paid | **(3,664)** | (3,525) | (3,334) |
| Other | **(78)** | (64) | (3,621) |
| Net Cash Used in Financing Activities | **(1,429)** | (2,574) | (7,133) |
| | | | |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | **(182)** | (214) | (75) |
| | | | |
| **Net Change in Cash and Cash Equivalents** | **(2,694)** | (1,184) | 2,628 |
| Cash and cash equivalents at beginning of period | **5,062** | 6,246 | 3,618 |
| Cash and Cash Equivalents at End of Period | **$ 2,368** | 5,062 | 6,246 |

**Certain amounts have been reclassified to conform to current-period presentation. See Note 21—Cash Flow Information, in the Notes to Consolidated Financial Statements.*

*See Notes to Consolidated Financial Statements.*

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Attributable to ConocoPhillips | | | | | | | | |
| | Common Stock | | | | | | | | |
| | | Par Value | Capital in Excess of Par | Treasury Stock | Accum. Other Comprehensive Income (Loss) | Retained Earnings | Non-Controlling Interests | Total |
| December 31, 2012 | $ | 18 | 45,324 | (36,780) | 4,087 | 35,338 | 440 | 48,427 |
| Net income | | | | | | 9,156 | 59 | 9,215 |
| Other comprehensive loss | | | | | (2,085) | | | (2,085) |
| Dividends paid | | | | | | (3,334) | | (3,334) |
| Distributions to noncontrolling interests and other | | | | | | | (97) | (97) |
| Distributed under benefit plans | | | 366 | | | | | 366 |
| December 31, 2013 | $ | 18 | 45,690 | (36,780) | 2,002 | 41,160 | 402 | 52,492 |
| Net income | | | | | | 6,869 | 69 | 6,938 |
| Other comprehensive loss | | | | | (3,904) | | | (3,904) |
| Dividends paid | | | | | | (3,525) | | (3,525) |
| Distributions to noncontrolling interests and other | | | | | | | (109) | (109) |
| Distributed under benefit plans | | | 381 | | | | | 381 |
| December 31, 2014 | $ | 18 | 46,071 | (36,780) | (1,902) | 44,504 | 362 | 52,273 |
| Net income (loss) | | | | | | **(4,428)** | **57** | **(4,371)** |
| Other comprehensive loss | | | | | **(4,345)** | | | **(4,345)** |
| Dividends paid | | | | | | **(3,664)** | | **(3,664)** |
| Distributions to noncontrolling interests and other | | | | | | | **(100)** | **(100)** |
| Distributed under benefit plans | | | **286** | | | | | **286** |
| Other | | | | | | **2** | **1** | **3** |
| **December 31, 2015** | **$** | **18** | **46,357** | **(36,780)** | **(6,247)** | **36,414** | **320** | **40,082** |

*See Notes to Consolidated Financial Statements.*

## Note 1—Accounting Policies

- **Consolidation Principles and Investments—**Our consolidated financial statements include the accounts of majority-owned, controlled subsidiaries and variable interest entities where we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we have the ability to exert significant influence over the affiliates' operating and financial policies. When we do not have the ability to exert significant influence, the investment is either classified as available-for-sale if fair value is readily determinable, or the cost method is used if fair value is not readily determinable. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants and terminals are consolidated on a proportionate basis. Other securities and investments are generally carried at cost.

  We manage our operations through six operating segments, defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International. Effective November 1, 2015, the Other International and historically presented Europe segments were restructured to align with changes to our internal organization structure. The Libya business was moved from the Other International segment to the historically presented Europe segment, which is now renamed Europe and North Africa. Certain financial information has been revised for all prior periods presented to reflect the change in the composition of our operating segments. For additional information, see Note 24—Segment Disclosures and Related Information. Unless indicated otherwise, the information in the Notes to the Consolidated Financial Statements relates to our continuing operations.

- **Foreign Currency Translation—**Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in accumulated other comprehensive income in common stockholders' equity. Foreign currency transaction gains and losses are included in current earnings. Most of our foreign operations use their local currency as the functional currency.

- **Use of Estimates—**The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from these estimates.

- **Revenue Recognition—**Revenues associated with sales of crude oil, bitumen, natural gas, liquefied natural gas (LNG), natural gas liquids and other items are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, either immediately or within a fixed delivery schedule that is reasonable and customary in the industry.

  Revenues associated with producing properties in which we have an interest with other producers are recognized based on the actual volumes we sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, which are deemed to be nonrecoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are generally not significant.

  Revenues associated with transactions commonly called buy/sell contracts, in which the purchase and sale of inventory with the same counterparty are entered into "in contemplation" of one another, are combined and reported net (i.e., on the same income statement line).

- **Shipping and Handling Costs—**We include shipping and handling costs in production and operating expenses for production activities. Transportation costs related to marketing activities are recorded in purchased commodities. Freight costs billed to customers are recorded as a component of revenue.

- **Cash Equivalents—**Cash equivalents are highly liquid, short-term investments that are readily convertible to known amounts of cash and have original maturities of 90 days or less from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.

- **Short-Term Investments**—Investments in bank time deposits and marketable securities (commercial paper and government obligations) with original maturities of greater than 90 days but less than one year are classified as short-term investments.

- **Inventories—**We have several valuation methods for our various types of inventories and consistently use the following methods for each type of inventory. Commodity-related inventories are valued at the lower of cost or market in the aggregate, primarily on the last-in, first-out (LIFO) basis. Any necessary lower-of-cost-or-market write-downs at year end are recorded as permanent adjustments to the LIFO cost basis. LIFO is used to better match current inventory costs with current revenues. Costs include both direct and indirect expenditures incurred in bringing an item or product to its existing condition and location, but not unusual/nonrecurring costs or research and development costs. Materials, supplies and other miscellaneous inventories, such as tubular goods and well equipment, are valued using various methods, including the weighted-average-cost method, and the first-in, first-out (FIFO) method, consistent with industry practice.

- **Fair Value Measurements—**We categorize assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1 for the asset or liability, either directly or indirectly through market-corroborated inputs. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or our assumptions about pricing by market participants.

- **Derivative Instruments—**Derivative instruments are recorded on the balance sheet at fair value. If the right of offset exists and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the balance sheet and the collateral payable or receivable is netted against derivative assets and derivative liabilities, respectively.

  Recognition and classification of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives not accounted for as hedges are recognized immediately in earnings. For derivative instruments that are designated and qualify as a fair value hedge, the gains or losses from adjusting the derivative to its fair value will be immediately recognized in earnings and, to the extent the hedge is effective, offset the concurrent recognition of changes in the fair value of the hedged item.

- **Oil and Gas Exploration and Development—**Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

  **Property Acquisition Costs—**Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption properties, plants and equipment (PP&E). Leasehold impairment is recognized based on exploratory experience and management's judgment. Upon achievement of all conditions necessary for reserves to be classified as proved, the associated leasehold costs are reclassified to proved properties.

  **Exploratory Costs—**Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized, or "suspended," on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas resources are designated as proved reserves.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as dry holes when it judges the potential field does not warrant further investment in the near term. See Note 8—Suspended Wells and Other Exploration Expenses, for additional information on suspended wells.

**Development Costs—**Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

**Depletion and Amortization—**Leasehold costs of producing properties are depleted using the unit-of-production method based on estimated proved oil and gas reserves. Amortization of intangible development costs is based on the unit-of-production method using estimated proved developed oil and gas reserves.

- **Capitalized Interest—**Interest from external borrowings is capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets.

- **Depreciation and Amortization—**Depreciation and amortization of PP&E on producing hydrocarbon properties and certain pipeline assets (those which are expected to have a declining utilization pattern), are determined by the unit-of-production method. Depreciation and amortization of all other PP&E are determined by either the individual-unit-straight-line method or the group-straight-line method (for those individual units that are highly integrated with other units).

- **Impairment of Properties, Plants and Equipment—**PP&E used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. If there is an indication the carrying amount of an asset may not be recovered, the asset is monitored by management through an established process where changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted pre-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value through additional amortization or depreciation provisions and reported as impairments in the periods in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for exploration and production assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell, with fair value determined using a binding negotiated price, if available, or present value of expected future cash flows as previously described.

  The expected future cash flows used for impairment reviews and related fair value calculations are based on estimated future production volumes, prices and costs, considering all available evidence at the date of review. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. Additionally, when probable and possible reserves exist, an appropriate risk-adjusted amount of these reserves may be included in the impairment calculation.

- **Impairment of Investments in Nonconsolidated Entities—**Investments in nonconsolidated entities are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred and annually following updates to corporate planning assumptions. When such a condition is judgmentally determined to be other than temporary, the carrying value of the investment is written down to fair value. The fair value of the impaired investment is based on quoted market prices, if available, or upon the present value of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate.

- **Maintenance and Repairs—**Costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

- **Property Dispositions—**When complete units of depreciable property are sold, the asset cost and related accumulated depreciation are eliminated, with any gain or loss reflected in the "Gain on dispositions" line of our consolidated income statement. When less than complete units of depreciable property are disposed of or retired, the difference between asset cost and salvage value is charged or credited to accumulated depreciation.

- **Asset Retirement Obligations and Environmental Costs—**The fair value of legal obligations to retire and remove long-lived assets are recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time the liability is increased for the change in its present value, and the capitalized cost in PP&E is depreciated over the useful life of the related asset. For additional information, see Note 10—Asset Retirement Obligations and Accrued Environmental Costs.

  Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures relating to an existing condition caused by past operations, and those having no future economic benefit, are expensed. Liabilities for environmental expenditures are recorded on an undiscounted basis (unless acquired in a purchase business combination) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is probable and estimable.

- **Guarantees—**The fair value of a guarantee is determined and recorded as a liability at the time the guarantee is given. The initial liability is subsequently reduced as we are released from exposure under the guarantee. We amortize the guarantee liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of guarantee. In cases where the guarantee term is indefinite, we reverse the liability when we have information indicating the liability is essentially relieved or amortize it over an appropriate time period as the fair value of our guarantee exposure declines over time. We amortize the guarantee liability to the related income statement line item based on the nature of the guarantee. When it becomes probable that we will have to perform on a guarantee, we accrue a separate liability if it is reasonably estimable, based on the facts and circumstances at that time. We reverse the fair value liability only when there is no further exposure under the guarantee.

- **Share-Based Compensation—**We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award) or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. We have elected to recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

- **Income Taxes—**Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial reporting basis and the tax basis of our assets and liabilities, except for deferred taxes on income and temporary differences related to the cumulative translation adjustment considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures. Allowable tax credits are applied currently as reductions of the provision for income taxes. Interest related to unrecognized tax benefits is reflected in interest and debt expense, and penalties related to unrecognized tax benefits are reflected in production and operating expenses.

- **Taxes Collected from Customers and Remitted to Governmental Authorities—**Sales and value-added taxes are recorded net.

- **Net Income (Loss) Per Share of Common Stock—**Basic net income (loss) per share of common stock is calculated based upon the daily weighted-average number of common shares outstanding during the year, including unallocated shares held by the stock savings feature of the ConocoPhillips Savings Plan. Also, this calculation includes fully vested stock and unit awards that have not yet been issued as common stock, along with an adjustment to net income (loss) for dividend equivalents paid on unvested unit awards that are considered participating securities. Diluted net income per share of common stock includes unvested stock, unit or option awards granted under our compensation plans and vested but unexercised stock options, but only to the extent these instruments dilute net income per share, primarily under the treasury-stock method. Diluted net loss per share, which is calculated the same as basic net loss per share, does not assume conversion or exercise of securities that would have an antidilutive effect. Treasury stock and shares held by grantor trusts are excluded from the daily weighted-average number of common shares outstanding in both calculations. The earnings per share impact of the participating securities is immaterial.

## Note 2—Changes in Accounting Principles

We adopted the provisions of Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) No. 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity," on a prospective basis, beginning January 1, 2015. The ASU amends the criteria for reporting discontinued operations to include only disposals representing a strategic shift in operations that have or will have a major effect on an entity's operations and financial results. The ASU also requires entities to provide additional disclosures about discontinued operations as well as certain other significant disposal transactions that do not meet the revised discontinued operations reporting criteria. The adoption of this ASU did not have a material impact on our consolidated financial statements and disclosures. See Note 3—Discontinued Operations, and Note 6—Assets Held for Sale or Sold, for additional information on our dispositions.

Effective December 31, 2015, we early adopted, on a prospective basis, FASB ASU No. 2015-17, "Balance Sheet Classification of Deferred Taxes." The ASU requires all deferred tax assets and liabilities, along with any related valuation allowances, to be offset and presented as a single noncurrent amount in a classified balance sheet for each tax-paying component within a tax jurisdiction. See Note 19—Income Taxes, for additional information.

## Note 3—Discontinued Operations

In 2012, we agreed to sell our interest in the North Caspian Sea Production Sharing Agreement (Kashagan) and our Nigeria and Algeria businesses (collectively, the "Disposition Group"). The Disposition Group was previously part of the Other International operating segment. We completed the sales of Kashagan and our Algeria business in the fourth quarter of 2013. We sold our Nigeria business in the third quarter of 2014.

On November 26, 2012, we notified government authorities in Kazakhstan and co-venturers of our intent to sell the company's 8.4 percent interest in Kashagan to ONGC Videsh Limited (OVL). On July 2, 2013, we received notification from the government of Kazakhstan indicating it was exercising its right to pre-empt the proposed sale to OVL and designating KazMunayGas (KMG) as the entity to acquire the interest. On October 31, 2013, we completed the transaction with KMG for total proceeds of $5,392 million and recognized a pre-tax gain of $22 million, which is included in the "Income from discontinued operations" line on our consolidated income statement. At the time of disposition, the carrying value of the net assets related to our interest in Kashagan was $5,370 million, which included $212 million of other current assets, $239 million of long-term receivables, $5,149 million of PP&E, $144 million of other current liabilities, and $86 million of asset retirement obligations (ARO).

On December 18, 2012, we entered into an agreement with Pertamina to sell our wholly owned subsidiary, ConocoPhillips Algeria Ltd. On November 27, 2013, we completed the transaction with Pertamina, resulting in proceeds of $1,652 million. We recognized a pre-tax gain of $938 million, which is included in the "Income from discontinued operations" line on our consolidated income statement. At the time of disposition, the net carrying value of our Algerian assets was $714 million, which included $48 million of other current assets, $883 million of PP&E, $41 million of other current liabilities, $37 million of ARO, and $139 million of deferred taxes.

On December 20, 2012, we entered into agreements with affiliates of Oando PLC to sell our Nigeria business and on July 30, 2014, we completed the sale for $1,359 million, inclusive of $550 million deposits previously received. The deposits had been included in the "Other accruals" line on our consolidated balance sheet and in the "Other" line of cash flows from investing activities on our consolidated statement of cash flows. The deposits received included $435 million in 2012, $15 million in 2013, and $100 million in 2014. We recognized a before-tax gain of $1,052 million, which is included in the "Income from discontinued operations" line on our consolidated income statement. At the time of disposition, the net carrying value of the upstream assets was $307 million, which included $233 million of other current assets, $1,211 million of PP&E, $298 million of other current liabilities, $14 million of ARO, and $825 million of deferred taxes.

Sales and other operating revenues and income from discontinued operations related to the Disposition Group during 2014 and 2013 were as follows:

| | Millions of Dollars | |
|---|---|---|
| | 2014 | 2013 |
| Sales and other operating revenues from discontinued operations | $ 480 | 1,185 |
| Income from discontinued operations before-tax | $ 1,147 | 1,461 |
| Income tax expense | 16 | 283 |
| Income from discontinued operations | $ 1,131 | 1,178 |

**Note 4—Variable Interest Entities (VIEs)**

We hold variable interests in VIEs that have not been consolidated because we are not considered the primary beneficiary. Information on our significant VIE follows:

**Australia Pacific LNG Pty Ltd (APLNG)**
APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary of APLNG because we share with Origin Energy and China Petrochemical Corporation (Sinopec) the power to direct the key activities of APLNG that most significantly impact its economic performance, which involve activities related to the production and commercialization of coalbed methane, as well as LNG processing and export marketing. As a result, we do not consolidate APLNG, and it is accounted for as an equity method investment.

As of December 31, 2015, we have not provided any financial support to APLNG other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of APLNG. See Note 7—Investments, Loans and Long-Term Receivables, and Note 12—Guarantees, for additional information.

**Note 5—Inventories**

Inventories at December 31 were:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2015** | 2014 |
| Crude oil and natural gas | $ | **406** | 538 |
| Materials and supplies | | **718** | 793 |
| | $ | **1,124** | 1,331 |

As a result of further declining commodity prices in the fourth quarter of 2015, we recorded a lower of cost or market adjustment of $44 million to our commodity inventories, which is included in the "Purchased commodities" line on our consolidated income statement. Inventories valued on the LIFO basis totaled $317 million and $440 million at December 31, 2015 and 2014, respectively. The estimated excess of current replacement cost over LIFO cost of inventories was approximately $6 million at both December 31, 2015 and December 31, 2014. In 2015, liquidation of LIFO inventory values increased the net loss from continuing operations by $25 million.

**Note 6—Assets Held for Sale or Sold**

**Assets Held for Sale**
On February 4, 2016, we entered into a definitive agreement to sell our interest in the Alaska Beluga River Unit natural gas field in the Cook Inlet. The transaction is expected to close in the second quarter of 2016.

**Assets Sold**
All gains or losses are reported before-tax and are included net in the "Gain on dispositions" line on our consolidated income statement.

*2015*
In November 2015, we sold a portion of our western Canadian properties located in British Columbia, Alberta, and Saskatchewan for $198 million and recognized a gain on disposition of $66 million. At the time of the disposition, the carrying value of our interest, which was included in the Canada segment, was $132 million, which included primarily $379 million of PP&E and $248 million of ARO.

In December 2015, we sold a portion of our western Canadian properties located in central Alberta for $130 million and recognized a loss on disposition of $235 million. At the time of the disposition, the carrying value of our interest, which was included in the Canada segment, was approximately $365 million, which included primarily $488 million of PP&E and $126 million of ARO.

Additionally, other December 2015 disposition transactions are summarized below.

We sold producing properties in East Texas and Northern Louisiana for $412 million and recognized a gain on disposition of $189 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $223 million, which included $351 million of PP&E and $128 million of ARO.

We sold certain gas producing properties in South Texas for $358 million and recognized a gain on disposition of $201 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $157 million, which included $369 million of PP&E and $212 million of ARO.

We sold certain pipeline and gathering assets in South Texas for $201 million and recognized a gain on disposition of $193 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $8 million, which primarily included $24 million of PP&E and $18 million of ARO.

We also sold our 50 percent interest in the Russian joint venture, Polar Lights Company, for $98 million and recognized a gain on disposition of $58 million. At the time of the disposition, the carrying value of our equity method investment in Polar Lights Company, which was included in our Other International segment, was approximately $40 million.

*2014*

For information on the sale of our Nigeria business, which is included in the "Income from discontinued operations" line on our consolidated income statement, see Note 3—Discontinued Operations.

*2013*

In March 2013, we sold the majority of our producing zones in the Cedar Creek Anticline for $994 million and recognized a loss on disposition of $43 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $1,037 million, which included primarily $1,066 million of PP&E and $28 million of ARO.

In June 2013, we sold a portion of our working interests in the Browse and Canning basins for $402 million. Because we retain a working interest in the unproved properties, proceeds were treated as a reduction of the carrying value of PP&E with no gain or loss on disposition recognized. Prior to the partial disposition, the carrying value of the PP&E associated with our interests, included in our Asia Pacific and Middle East segment, was $486 million.

In August 2013, we sold our interest in the Clyden undeveloped oil sands leasehold for $724 million and recognized a gain on disposition of $614 million. At the time of the disposition, the carrying value of our interest in Clyden, which was included in the Canada segment, was $110 million and was primarily classified as PP&E.

In August 2013, we also sold our 39 percent interest in Phoenix Park Gas Processors Limited for $593 million and recognized a gain on disposition of $417 million. At the time of the disposition, the carrying value of our equity investment in Phoenix Park, which was included in our Other International segment, was $176 million.

For information on the Kashagan and Algeria sales, which are included in the "Income from discontinued operations" line on our consolidated income statement, see Note 3—Discontinued Operations.

## Note 7—Investments, Loans and Long-Term Receivables

Components of investments, loans and long-term receivables at December 31 were:

| | Millions of Dollars | |
|---|---|---|
| | **2015** | 2014 |
| Equity investments | $ **19,850** | 23,426 |
| Loans and advances—related parties | **696** | 804 |
| Long-term receivables | **519** | 444 |
| Other investments | **121** | 465 |
| | $ **21,186** | 25,139 |

**Equity Investments**
Affiliated companies in which we had a significant equity investment at December 31, 2015, included:

- APLNG—37.5 percent owned joint venture with Origin Energy (37.5 percent) and Sinopec (25 percent)—to develop coalbed methane production from the Bowen and Surat basins in Queensland, Australia, as well as process and export LNG.
- FCCL Partnership—50 percent owned business venture with Cenovus Energy Inc.—produces bitumen in the Athabasca oil sands in northeastern Alberta and sells the bitumen blend.
- Qatar Liquefied Gas Company Limited (3) (QG3)—30 percent owned joint venture with affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent)—produces and liquefies natural gas from Qatar's North Field, as well as exports LNG.

Summarized 100 percent earnings information for equity method investments in affiliated companies, combined, was as follows:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2015** | 2014 | 2013 |
| Revenues | $ **11,003** | 19,243 | 18,035 |
| Income before income taxes | **1,866** | 6,746 | 6,384 |
| Net income | **1,801** | 6,630 | 6,125 |

Summarized 100 percent balance sheet information for equity method investments in affiliated companies, combined, was as follows:

| | Millions of Dollars | |
|---|---|---|
| | **2015** | 2014 |
| Current assets | $ **2,504** | 4,512 |
| Noncurrent assets | **58,431** | 58,570 |
| Current liabilities | **1,863** | 3,346 |
| Noncurrent liabilities | **24,820** | 20,210 |

Our share of income taxes incurred directly by an equity company is reported in equity in earnings of affiliates, and as such is not included in income taxes in our consolidated financial statements.

At December 31, 2015, retained earnings included $1,323 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $876 million, $2,648 million and $1,425 million in 2015, 2014 and 2013, respectively.

**APLNG**
APLNG is focused on coalbed methane production from the Bowen and Surat basins in Queensland, Australia, and LNG processing and export sales. Our investment in APLNG gives us access to coalbed methane resources in Australia and enhances our LNG position. The majority of APLNG LNG is sold under two long term sales and purchase agreements, supplemented with sales of additional LNG spot cargoes targeting the Asia Pacific markets. Origin Energy, an integrated Australian energy company, is the operator of APLNG's production and pipeline system, while we operate the LNG facility.

APLNG executed project financing agreements for an $8.5 billion project finance facility during the third quarter of 2012. The $8.5 billion project finance facility is composed of financing agreements executed by APLNG with the Export-Import Bank of the United States for approximately $2.9 billion, the Export-Import Bank of China for approximately $2.7 billion, and a syndicate of Australian and international commercial banks for approximately $2.9 billion. At December 31, 2015, $8.4 billion had been drawn from the facility. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility which will be released upon meeting certain completion milestones. See Note 12—Guarantees, for additional information.

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. See Note 4—Variable Interest Entities (VIEs) for additional information.

During 2015, the outlook for crude oil and natural gas prices sharply deteriorated, and as a result of these significantly reduced price outlooks, the estimated fair value of our investment in APLNG declined to an amount below book value during the fourth quarter of 2015.

Based on a review of the facts and circumstances surrounding this decline in fair value, we concluded that the impairment was other than temporary under the guidance of FASB Accounting Standards Codification (ASC) Topic 323, "Investments – Equity Method and Joint Ventures," and the recognition of an impairment of our investment to fair value was necessary. In reaching this conclusion, we primarily considered the severity of the current decline of commodity prices as well as the market outlook. Fair value has been estimated based on an internal discounted cash flow model using estimates of future production, prices from futures exchanges and pricing service companies, costs, foreign currency rates and a discount factor that is believed to be consistent with those used by principal market participants.

Accordingly, we recorded a noncash $1,502 million, before- and after-tax impairment, in our fourth-quarter 2015 results. The impairment, which is included in the "Impairments" line on our consolidated income statement, had the effect of reducing our book value to $10,185 million, based on the present value of discounted expected future cash flows as of December 31, 2015.

At December 31, 2015, the book value of our equity method investment in APLNG was $10,185 million, net of a $1,522 million reduction due to cumulative foreign currency translation effects. Effective October 1, 2015, in conjunction with APLNG Train 1 achieving first LNG during the fourth quarter, we changed the functional currency of our investment in APLNG from Australian dollar to U.S. dollar. Accordingly, we expect the currency translation adjustment associated with our investment balance to remain unchanged going forward. The historical cost basis of our 37.5 percent share of net assets on the books of APLNG under U.S. generally accepted accounting principles was $7,470 million, resulting in a basis difference of $2,715 million on our books. The basis difference, which is substantially all associated with PP&E and subject to amortization, has been allocated on a relative fair value basis to individual exploration and production license areas owned by APLNG, some of which are not currently in production. Any future additional payments are expected to be allocated in a similar manner. Each exploration license area will periodically be reviewed for any indicators of potential impairment, which, if required, would result in acceleration of basis difference amortization. As the joint venture produces natural gas from each license, we amortize the basis difference allocated to that license using the unit-of-production method. Included in net income (loss) attributable to ConocoPhillips for 2015, 2014 and 2013 was after-tax expense of $21 million, $24 million and $16 million, respectively, representing the amortization of this basis difference on currently producing licenses.

**FCCL**
FCCL Partnership, a Canadian upstream 50/50 general partnership with Cenovus Energy Inc., produces bitumen in the Athabasca oil sands in northeastern Alberta and sells the bitumen blend. We account for our investment in FCCL under the equity method of accounting, with the operating results of our investment in FCCL converted to reflect the use of the successful efforts method of accounting for oil and gas exploration and development activities.

At December 31, 2015, the book value of our investment in FCCL was $8,165 million, net of a $1,955 million reduction due to cumulative foreign currency translation effects. FCCL's operating assets consist of the Foster Creek and Christina Lake steam-assisted gravity drainage bitumen projects, both located in the eastern flank of the Athabasca oil sands in northeastern Alberta. Cenovus is the operator and managing partner of FCCL.

We were obligated to contribute $7.5 billion, plus accrued interest, to FCCL over a 10-year period that began in 2007. In December 2013, we repaid the remaining balance of the obligation, which totaled $2,810 million and is included in the "Other" line in the financing activities section of our consolidated statement of cash flows. Interest accrued at a fixed annual rate of 5.3 percent on the unpaid principal balance. Fifty percent of the quarterly interest payment is reflected as a capital contribution and is included in the "Capital expenditures and investments" line on our consolidated statement of cash flows. In the first quarter of 2014, we received a $1.3 billion distribution from FCCL, which is included in the "Undistributed equity earnings" line on our consolidated statement of cash flows.

**QG3**
QG3 is a joint venture that owns an integrated large-scale LNG project located in Qatar. We provided project financing, with a current outstanding balance of $804 million as described below under "Loans and Long-Term Receivables." At December 31, 2015, the book value of our equity method investment in QG3, excluding the project financing, was $808 million. We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliated Golden Pass Pipeline near Sabine Pass, Texas, in which we have a 12.4 percent interest, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from QG3. However, currently the LNG from QG3 is being sold to markets outside of the United States.

**Loans and Long-Term Receivables**
As part of our normal ongoing business operations and consistent with industry practice, we enter into numerous agreements with other parties to pursue business opportunities. Included in such activity are loans and long-term receivables to certain affiliated and non-affiliated companies. Loans are recorded when cash is transferred or seller financing is provided to the affiliated or non-affiliated company pursuant to a loan agreement. The loan balance will increase as interest is earned on the outstanding loan balance and will decrease as interest and principal payments are received. Interest is earned at the loan agreement's stated interest rate. Loans and long-term receivables are assessed for impairment when events indicate the loan balance may not be fully recovered.

Through November 2014, we had an agreement with Freeport LNG Development, L.P. (Freeport LNG) to participate in an LNG receiving terminal in Quintana, Texas. We had no ownership in Freeport LNG; however, we had a 50 percent interest in Freeport LNG GP, Inc. (Freeport GP), which serves as the general partner managing the venture. We had entered into a credit agreement with Freeport LNG, whereby we agreed to provide loan financing for the construction of the terminal. We also entered into a long-term agreement with Freeport LNG to use 0.9 billion cubic feet per day of regasification capacity, which would have expired in 2033. When the terminal became operational in June 2008, we began making payments under the terminal use agreement. Freeport LNG began making loan repayments in September 2008.

In July 2013, we reached an agreement with Freeport LNG to terminate our long-term agreement at the Freeport LNG Terminal, subject to Freeport LNG obtaining regulatory approval and project financing for an LNG liquefaction and export facility in Texas, in which we are not a participant. These conditions were satisfied in 2014, and we paid Freeport LNG a termination fee of $522 million. Freeport LNG repaid the outstanding $454 million ConocoPhillips loan used by Freeport LNG to partially fund the original construction of the terminal. The payment made to Freeport LNG to terminate our long-term agreement is included in the cash flows from operating activities section on our consolidated statement of cash flows, while the receipt of the funds from Freeport LNG to repay the outstanding loan is included in the cash flows from investing activities section. These transactions, plus miscellaneous items, including the disposal of our 50 percent interest in Freeport GP, resulted in a one-time net cash outflow of $63 million for us. In addition, we recognized an after-tax charge to earnings of $540 million in 2014, and our terminal regasification capacity has been reduced from 0.9 billion cubic feet per day to 0.4 billion cubic feet per day, until July 1, 2016, at which time it will be reduced to zero.

At December 31, 2015, significant loans to affiliated companies include $804 million in project financing to QG3. We own a 30 percent interest in QG3, for which we use the equity method of accounting. The other participants in the project are affiliates of Qatar Petroleum and Mitsui. QG3 secured project financing of $4.0 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. On December 15, 2011, QG3 achieved financial completion and all project loan facilities became nonrecourse to the project participants. Semi-annual repayments began in January 2011 and will extend through July 2022.

The long-term portion of these loans is included in the "Loans and advances—related parties" line on our consolidated balance sheet, while the short-term portion is in "Accounts and notes receivable—related parties."

**Note 8—Suspended Wells and Other Exploration Expenses**

The following table reflects the net changes in suspended exploratory well costs during 2015, 2014 and 2013:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| Beginning balance at January 1 | $ | **1,299** | 994 | 1,038 |
| Additions pending the determination of proved reserves | | **331** | 478 | 466 |
| Reclassifications to proved properties | | **(28)** | (9) | (29) |
| Sales of suspended well investment | | **-** | (57) | (481) |
| Charged to dry hole expense | | **(342)** | (107) | - |
| Ending balance at December 31 | $ | **1,260** | 1,299 | 994 * |

**Includes $57 million of assets that were held for sale in Nigeria.*

The following table provides an aging of suspended well balances at December 31:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| Exploratory well costs capitalized for a period of one year or less | $ | **235** | 466 | 437 |
| Exploratory well costs capitalized for a period greater than one year | | **1,025** | 833 | 557 |
| Ending balance | $ | **1,260** | 1,299 | 994 * |
| Number of projects with exploratory well costs capitalized for a period greater than one year | | **28** | 30 | 29 |

**Includes $57 million of assets that were held for sale in Nigeria.*

The following table provides a further aging of those exploratory well costs that have been capitalized for more than one year since the completion of drilling as of December 31, 2015:

| | | Millions of Dollars | | | |
|---|---|---|---|---|---|
| | | | Suspended Since | | |
| | | Total | 2012–2014 | 2009–2011 | 2002–2008 |
| Greater Poseidon—Australia(2) | | 177 | 165 | 12 | - |
| Caldita/Barossa—Australia(1) | | 77 | - | - | 77 |
| FAN—Senegal(1) | | 117 | 117 | - | - |
| Fiord West—Alaska(2) | | 16 | - | - | 16 |
| Greater Clair—UK(2) | | 127 | 113 | 14 | - |
| Kamunsu East—Malaysia(2) | | 19 | 19 | - | - |
| Limbayong—Malaysia(1) | | 23 | 23 | - | - |
| NC 98—Libya(2) | | 15 | 11 | - | 4 |
| NPRA—Alaska(1) | | 93 | 70 | 17 | 6 |
| Shenandoah—Lower 48(1) | | 94 | 51 | 43 | - |
| SNE—Senegal(1) | | 23 | 23 | - | - |
| Sunrise—Australia(2) | | 13 | - | - | 13 |
| Surmont 3 and beyond—Canada(1) | | 89 | 58 | 14 | 17 |
| Tiber—Lower 48(1) | | 100 | 60 | 40 | - |
| Other of $10 million or less each(1)(2) | | 42 | 24 | 2 | 16 |
| Total | $ | 1,025 | 734 | 142 | 149 |

*(1)Additional appraisal wells planned.*
*(2)Appraisal drilling complete; costs being incurred to assess development.*

In line with our July 2015 announcement of plans to reduce future deepwater exploration spending, we recognized before-tax cancellation costs of $335 million and wrote off $48 million of before-tax capitalized rig costs in relation to the termination of our Gulf of Mexico deepwater drillship contract with Ensco in the Lower 48 segment in the third quarter of 2015.

In the fourth quarter of 2015, we impaired our leasehold cost associated with Block 36 in Angola due to the lack of commerciality of future prospects. We drilled one of our two-well commitment under the Angola Block 36 Production Sharing Contract (PSC) and recorded a before-tax charge of $93 million for potential future obligations.

These charges are included in the “Exploration expenses” line on our consolidated income statement.

**Note 9—Impairments**

During 2015, 2014 and 2013, we recognized the following before-tax impairment charges:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2015** | 2014 | 2013 |
| Alaska | $ **10** | 59 | 3 |
| Lower 48 | **(2)** | 208 | 2 |
| Canada | **4** | 38 | 216 |
| Europe and North Africa | **724** | 541 | 301 |
| Asia Pacific and Middle East | **1,508** | 7 | 3 |
| Corporate | **1** | 3 | 4 |
| | $ **2,245** | 856 | 529 |

_2015_
See the "APLNG" section of Note 7—Investments, Loans and Long-Term Receivables, for information on the impairment of our APLNG investment included within the Asia Pacific and Middle East segment.

In Europe, we recorded impairments of $724 million, primarily in the United Kingdom as a result of lower natural gas prices and increases to asset retirement obligations.

The charges discussed below, within this section, are included in the "Exploration expenses" line on our consolidated income statement and are not reflected in the table above.

In the second and fourth quarters of 2015, we decided not to pursue further evaluation of our Block 37 and Block 36 leases in Angola, respectively, due to lack of commerciality of wells. Accordingly, we recorded impairments of $116 million in the second quarter of 2015 and $377 million in the fourth quarter of 2015 for the associated carrying values of capitalized undeveloped leasehold costs.

In the third quarter of 2015, we decided not to conduct further activity on certain Gulf of Mexico leases, given our strategic plans to reduce deepwater exploration spending, and to relinquish our Palangkaraya PSC in Indonesia. Accordingly, we recorded impairments of $240 million and $105 million, respectively, for the associated carrying values of capitalized undeveloped leasehold cost.

In the fourth quarter of 2015, we recorded impairments of $575 million, $159 million and $102 million for the associated carrying value of capitalized undeveloped leasehold cost in the Chukchi Sea in Alaska; the Gila prospect in deepwater Gulf of Mexico; and the Duvernay, Thornbury, Saleski and Crow Lake areas in Canada, respectively. These impairments were driven by the lack of commerciality of wells, regulatory uncertainty and the expiration of our leases.

_2014_
In Alaska, we recorded impairments of $59 million, primarily due to a cancelled project.

In our Lower 48 segment, we recorded impairments of $208 million, primarily as a result of reduced volume forecasts for an onshore field, as well as an LNG-related pipeline.

We recorded impairments of $38 million in our Canada segment, primarily due to reduced volume forecasts and lower natural gas prices.

In Europe, we recorded impairments of $541 million, mainly due to reduced volume forecasts, increases in the ARO and lower natural gas prices for properties in the United Kingdom which are nearing the end of their useful lives.

The charges discussed below, within this section, are included in the "Exploration expenses" line on our consolidated income statement and are not reflected in the table above.

In our Lower 48 segment, we recorded unproved property impairments of $239 million, primarily due to decisions to discontinue further testing of the undeveloped leaseholds.

Additionally, we decided not to pursue future development of the Amauligak discovery. Accordingly, we recorded a $145 million property impairment for the carrying value of capitalized undeveloped leasehold costs associated with our Amauligak, Arctic Islands and other Beaufort properties located offshore Canada.

*2013*
We recorded property impairments of $216 million in our Canada segment, mainly as a result of lower natural gas price assumptions, reduced volume forecasts and higher costs.

In Europe, we recorded impairments of $301 million, primarily due to ARO revisions for properties in the United Kingdom which are nearing the end of their useful lives or have ceased production.

## Note 10—Asset Retirement Obligations and Accrued Environmental Costs

Asset retirement obligations and accrued environmental costs at December 31 were:

| | Millions of Dollars | |
|---|---|---|
| | **2015** | 2014 |
| Asset retirement obligations | $ **9,911** | 10,939 |
| Accrued environmental costs | **258** | 344 |
| Total asset retirement obligations and accrued environmental costs | **10,169** | 11,283 |
| Asset retirement obligations and accrued environmental costs due within one year* | **(589)** | (636) |
| Long-term asset retirement obligations and accrued environmental costs | $ **9,580** | 10,647 |

**Classified as a current liability on the balance sheet under "Other accruals."*

**Asset Retirement Obligations**
We record the fair value of a liability for an asset retirement obligation when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize the associated asset retirement cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time, the liability increases for the change in its present value, while the capitalized cost depreciates over the useful life of the related asset.

We have numerous asset retirement obligations we are required to perform under law or contract once an asset is permanently taken out of service. Most of these obligations are not expected to be paid until several years, or decades, in the future and will be funded from general company resources at the time of removal. Our largest individual obligations involve plugging and abandonment of wells and removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska.

During 2015 and 2014, our overall asset retirement obligation changed as follows:

| | Millions of Dollars | |
|---|---|---|
| | **2015** | 2014 |
| Balance at January 1 | **$ 10,939** | 10,076 |
| Accretion of discount | **480** | 479 |
| New obligations | **135** | 368 |
| Changes in estimates of existing obligations | **267** | 1,175 |
| Spending on existing obligations | **(437)** | (365) |
| Property dispositions | **(726)** | (20) |
| Foreign currency translation | **(747)** | (774) |
| Balance at December 31 | **$ 9,911** | 10,939 |

**Accrued Environmental Costs**
Total accrued environmental costs at December 31, 2015 and 2014, were $258 million and $344 million, respectively.

We had accrued environmental costs of $184 million and $250 million at December 31, 2015 and 2014, respectively, related to remediation activities in the United States and Canada. We had also accrued in Corporate and Other $57 million and $79 million of environmental costs associated with sites no longer in operation at December 31, 2015 and 2014, respectively. In addition, $17 million and $15 million were included at both December 31, 2015 and 2014, respectively, where the company has been named a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act, or similar state laws. Accrued environmental liabilities are expected to be paid over periods extending up to 30 years.

Expected expenditures for environmental obligations acquired in various business combinations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $105 million at December 31, 2015. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $12 million in 2016, $13 million in 2017, $9 million in 2018, $6 million in 2019, $4 million in 2020, and $117 million for all future years after 2020.

**Note 11—Debt**

Long-term debt at December 31 was:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2015** | 2014 |
| 9.125% Debentures due 2021 | $ | **150** | 150 |
| 8.20% Debentures due 2025 | | **150** | 150 |
| 8.125% Notes due 2030 | | **600** | 600 |
| 7.9% Debentures due 2047 | | **100** | 100 |
| 7.8% Debentures due 2027 | | **300** | 300 |
| 7.65% Debentures due 2023 | | **88** | 88 |
| 7.40% Notes due 2031 | | **500** | 500 |
| 7.375% Debentures due 2029 | | **92** | 92 |
| 7.25% Notes due 2031 | | **500** | 500 |
| 7.20% Notes due 2031 | | **575** | 575 |
| 7% Debentures due 2029 | | **200** | 200 |
| 6.95% Notes due 2029 | | **1,549** | 1,549 |
| 6.875% Debentures due 2026 | | **67** | 67 |
| 6.65% Debentures due 2018 | | **297** | 297 |
| 6.50% Notes due 2039 | | **2,250** | 2,250 |
| 6.50% Notes due 2039 | | **500** | 500 |
| 6.00% Notes due 2020 | | **1,000** | 1,000 |
| 5.951% Notes due 2037 | | **645** | 645 |
| 5.95% Notes due 2036 | | **500** | 500 |
| 5.90% Notes due 2032 | | **505** | 505 |
| 5.90% Notes due 2038 | | **600** | 600 |
| 5.75% Notes due 2019 | | **2,250** | 2,250 |
| 5.625% Notes due 2016 | | **1,250** | 1,250 |
| 5.20% Notes due 2018 | | **500** | 500 |
| 4.30% Notes due 2044 | | **750** | 750 |
| 4.15% Notes due 2034 | | **500** | 500 |
| 3.35% Notes due 2024 | | **1,000** | 1,000 |
| 3.35% Notes due 2025 | | **500** | - |
| 2.875% Notes due 2021 | | **750** | 750 |
| 2.4% Notes due 2022 | | **1,000** | 1,000 |
| 2.2% Notes due 2020 | | **500** | - |
| 1.5% Notes due 2018 | | **750** | - |
| 1.05% Notes due 2017 | | **1,000** | 1,000 |
| Floating rate notes due 2018 at 0.61% – 0.69% during 2015 | | **250** | - |
| Floating rate notes due 2022 at 1.18% – 1.26% during 2015 | | **500** | - |
| Commercial paper at 0.16% – 0.80% during 2015 and 0.14% – 0.21% during 2014 | | **803** | 860 |
| Industrial Development Bonds due 2015 through 2038 at 0.01% – 0.13% during 2015 and 0.02% – 0.13% during 2014 | | **18** | 18 |
| Marine Terminal Revenue Refunding Bonds due 2031 at 0.01% – 0.14% during 2015 and 0.02% – 0.15% during 2014 | | **265** | 265 |
| Other | | **24** | 24 |
| Debt at face value | | **23,778** | 21,335 |
| Capitalized leases | | **818** | 858 |
| Net unamortized premiums, discounts and debt issuance costs | | **284** | 372 |
| Total debt | | **24,880** | 22,565 |
| Short-term debt | | **(1,427)** | (182) |
| Long-term debt | $ | **23,453** | 22,383 |

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2016 through 2020 are: $1,427 million, $1,081 million, $1,859 million, $3,014 million and $1,576 million, respectively. At December 31, 2015, we classified $695 million of short-term debt as long-term debt, based on our ability and intent to refinance the obligation on a long-term basis under our revolving credit facility.

In May 2015, we issued notes consisting of:

- The $750 million of 1.50% Notes due 2018.
- The $250 million of Floating Rate Notes due 2018 bearing interest at three-month LIBOR, plus 0.33%.
- The $500 million of 2.20% Notes due 2020.
- The $500 million of Floating Rate Notes due 2022 bearing interest at three-month LIBOR, plus 0.90%.
- The $500 million of 3.35% Notes due 2025.

The net proceeds were used for general corporate purposes.

At December 31, 2015, we had a revolving credit facility totaling $7.0 billion expiring in June 2019. Our revolving credit facility may be used for direct bank borrowings, for the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper programs. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the United States. The agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

We have two commercial paper programs supported by our $7.0 billion revolving credit facility: the ConocoPhillips $6.1 billion program, primarily a funding source for short-term working capital needs, and the ConocoPhillips Qatar Funding Ltd. $900 million program, which is used to fund commitments relating to QG3. Commercial paper maturities are generally limited to 90 days.

At both December 31, 2015 and 2014, we had no direct outstanding borrowings under the revolving credit facility, with no letters of credit as of December 31, 2015 and 2014. In addition, under the ConocoPhillips Qatar Funding Ltd. commercial paper program, there was $803 million of commercial paper outstanding at December 31, 2015, compared with $860 million at December 31, 2014. Since we had $803 million of commercial paper outstanding and had issued no letters of credit, we had access to $6.2 billion in borrowing capacity under our revolving credit facility at December 31, 2015.

During 2013, a lease of a semi-submersible floating production system (FPS) commenced for the Gumusut development, located in Malaysia, in which we are a co-venturer. The FPS lease provides for an initial noncancelable term of 15 years, a subsequent 5-year cancelable term with no required lease payments, and an additional 5-year term with terms and conditions to be agreed at a later date. The lease has no ongoing purchase options or escalation clauses. Adjustments to provisional contingent rental payments may occur due to the finalization of actual commissioning costs. The lease does not impose any significant restrictions concerning dividends, debt or further leasing activities.

A capital lease asset and capital lease obligation were recognized for our proportionate interest in the FPS of $906 million, based on the present value of the future minimum lease payments using our pre-tax incremental borrowing rate of 3.58 percent for debt with similar terms. Unitization of the Gumusut development with

Brunei was recorded during the fourth quarter of 2014 and reduced our proportionate interest in the FPS from 33 percent to 29 percent. The net carrying value of the capital lease asset was approximately $707 million and $802 million as of December 31, 2015 and December 31, 2014, respectively. The capital lease asset is being depreciated over a period consistent with the estimated proved reserves of Gumusut using the unit-of-production method with the associated depreciation included in the "Depreciation, depletion and amortization" line on our consolidated income statement. As of December 31, 2015 and December 31, 2014, accumulated depreciation of the capital lease asset amounted to approximately $122 million and $20 million, respectively.

At December 31, 2015, future minimum payments due under capital leases were:

| | Millions of Dollars |
|---|---|
| 2016 | $ 91 |
| 2017 | 76 |
| 2018 | 76 |
| 2019 | 76 |
| 2020 | 76 |
| Remaining years | 648 |
| Total | 1,043 |
| Less: portion representing imputed interest | (225) |
| Capital lease obligations | $ 818 |

**Note 12—Guarantees**

At December 31, 2015, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability at inception for the fair value of our obligation as a guarantor for newly issued or modified guarantees. Unless the carrying amount of the liability is noted below, we have not recognized a liability because the fair value of the obligation is immaterial. In addition, unless otherwise stated, we are not currently performing with any significance under the guarantee and expect future performance to be either immaterial or have only a remote chance of occurrence.

**APLNG Guarantees**
At December 31, 2015, we had outstanding multiple guarantees in connection with our 37.5 percent ownership interest in APLNG. The following is a description of the guarantees with values calculated utilizing December 2015 exchange rates:

- We have guaranteed APLNG's performance with regard to a construction contract executed in connection with APLNG's issuance of the Train 1 and Train 2 Notices to Proceed. We estimate the remaining term of this guarantee is one year. Our maximum potential amount of future payments related to this guarantee is approximately $110 million and would become payable if APLNG cancels the applicable construction contract and does not perform with respect to the amounts owed to the contractor.

- We have issued a construction completion guarantee related to the third-party project financing secured by APLNG. Our maximum potential amount of future payments under the guarantee is estimated to be $3.2 billion, which could be payable if the full debt financing capacity is utilized and completion of the project is not achieved. Our guarantee of the project financing will be released upon meeting certain completion tests with milestones, which we estimate should occur beginning in 2016. Our maximum exposure at December 31, 2015, is $3.2 billion based upon our pro-rata share of the facility used at that date. At December 31, 2015, the carrying value of this guarantee is approximately $114 million.

- In conjunction with our original purchase of an ownership interest in APLNG from Origin Energy in October 2008, we agreed to reimburse Origin Energy for our share of the existing contingent liability arising under guarantees of an existing obligation of APLNG to deliver natural gas under several sales agreements with remaining terms of 1 to 26 years. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $1 billion ($1.8 billion in the event of intentional or reckless breach) and would become payable if APLNG fails to meet its obligations under these agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, would only be triggered if APLNG does not have enough natural gas to meet these sales commitments and if the co-venturers do not make necessary equity contributions into APLNG.

- We have guaranteed the performance of APLNG with regard to certain other contracts executed in connection with the project's continued development. The guarantees have remaining terms of up to 30 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $160 million and would become payable if APLNG does not perform.

**Other Guarantees**
We have other guarantees with maximum future potential payment amounts totaling approximately $590 million, which consist primarily of guarantees of the residual value of a leased office building, the residual value of leased corporate aircraft, a guarantee for our portion of a joint venture's project finance reserve accounts, a guarantee to fund the short-term cash liquidity deficit of a joint venture, and a guarantee of minimum charter revenue for an LNG vessel. These guarantees have remaining terms of up to eight years or the life of the venture and would become payable if, upon sale, certain asset values are lower than guaranteed amounts, business conditions decline at guaranteed entities, or as a result of nonperformance of contractual terms by guaranteed parties.

**Indemnifications**
Over the years, we have entered into agreements to sell ownership interests in certain corporations, joint ventures and assets that gave rise to qualifying indemnifications. These agreements include indemnifications for taxes, environmental liabilities, employee claims and litigation. The terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications at December 31, 2015, was approximately $90 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the recorded carrying amount at December 31, 2015, were approximately $40 million of environmental accruals for known contamination that are included in the "Asset retirement obligations and accrued environmental costs" line on our consolidated balance sheet. For additional information about environmental liabilities, see Note 13—Contingencies and Commitments.

On April 30, 2012, the separation of our Downstream businesses was completed, creating two independent energy companies: ConocoPhillips and Phillips 66. In connection with the separation, we entered into an Indemnification and Release Agreement, which provides for cross-indemnities between Phillips 66 and us and established procedures for handling claims subject to indemnification and related matters. We evaluated the impact of the indemnifications given and the Phillips 66 indemnifications received as of the separation date and concluded those fair values were immaterial.

On March 1, 2015, a supplier to one of the refineries that was included in Phillips 66 as part of the separation of our Downstream businesses formally registered Phillips 66 as a party to the supply agreement, thereby triggering a guarantee we provided at the time of separation. Our maximum potential liability for future payments under this guarantee, which would become payable if Phillips 66 does not perform its contractual obligations under the supply agreement, is approximately $1.6 billion. At December 31, 2015, the carrying value of this guarantee is approximately $98 million and the remaining term is nine years. Because Phillips 66 has indemnified us for losses incurred under this guarantee, we have recorded an indemnification asset from Phillips 66 of approximately $98 million. The recorded indemnification asset amount represents the estimated fair value of the guarantee; however, if we are required to perform under the guarantee, we would expect to recover from Phillips 66 any amounts in excess of that value, provided Phillips 66 is a going concern.

## Note 13—Contingencies and Commitments

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been made against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. With respect to income tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. See Note 19—Income Taxes, for additional information about income tax-related contingencies.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

### Environmental

We are subject to international, federal, state and local environmental laws and regulations. When we prepare our consolidated financial statements, we record accruals for environmental liabilities based on management's best estimates, using all information that is available at the time. We measure estimates and base liabilities on currently available facts, existing technology, and presently enacted laws and regulations, taking into account stakeholder and business considerations. When measuring environmental liabilities, we also consider our prior experience in remediation of contaminated sites, other companies' cleanup experience, and data released by the U.S. Environmental Protection Agency (EPA) or other organizations. We consider unasserted claims in our determination of environmental liabilities, and we accrue them in the period they are both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for other sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all cleanup costs related to any site at which we have been designated as a potentially responsible party. We have been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the agency concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, we consider this inability in estimating our potential liability, and we adjust our accruals accordingly. As a result of various acquisitions in the past, we assumed certain environmental obligations. Some of these environmental obligations are mitigated by indemnifications made by others for our benefit, and some of the indemnifications are subject to dollar limits and time limits.

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state and international sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. See Note 10—Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

**Legal Proceedings**
We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, personal injury, and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required.

**Other Contingencies**
We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at December 31, 2015, we had performance obligations secured by letters of credit of $340 million (issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, commercial activities and services incident to the ordinary conduct of business.

In 2007, we announced we had been unable to reach agreement with respect to our migration to an *empresa mixta* structure mandated by the Venezuelan government's Nationalization Decree. As a result, Venezuela's national oil company, Petróleos de Venezuela S.A. (PDVSA), or its affiliates, directly assumed control over ConocoPhillips' interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, we filed a request for international arbitration on November 2, 2007, with the World Bank's International Centre for Settlement of Investment Disputes (ICSID). An arbitration hearing was held before an ICSID tribunal during the summer of 2010. On September 3, 2013, an ICSID arbitration tribunal held that Venezuela unlawfully expropriated ConocoPhillips' significant oil investments in June 2007. A separate arbitration phase is currently proceeding to determine the damages owed to ConocoPhillips for Venezuela's actions. On October 10, 2014, we filed a separate arbitration under the rules of the International Chamber of Commerce against PDVSA for contractual compensation related to the Petrozuata and Hamaca heavy crude oil projects.

In 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before ICSID against The Republic of Ecuador, as a result of the newly enacted Windfall Profits Tax Law and government-mandated renegotiation of our production sharing contracts. Despite a restraining order issued by the ICSID tribunal, Ecuador confiscated the crude oil production of Burlington and its co-venturer and sold the seized crude oil. In 2009, Ecuador took over operations in Blocks 7 and 21, fully expropriating our assets. In June 2010, the ICSID tribunal concluded it has jurisdiction to hear the expropriation claim. On April 24, 2012, Ecuador filed supplemental counterclaims asserting environmental damages, which we believe are not material. The ICSID tribunal issued a decision on liability on December 14, 2012, in favor of Burlington, finding that Ecuador's seizure of Blocks 7 and 21 was an unlawful expropriation in violation of the Ecuador-U.S. Bilateral Investment Treaty. An additional arbitration phase is now proceeding to determine the damages owed to ConocoPhillips for Ecuador's actions and to address Ecuador's counterclaims.

ConocoPhillips served a Notice of Arbitration on the Timor-Leste Minister of Finance in October 2012 for outstanding disputes related to a series of tax assessments. The arbitration hearing was conducted in Singapore in June 2014 under the United Nations Commission on International Trade Laws (UNCITRAL) arbitration rules, pursuant to the terms of the Tax Stability Agreement with the Timor-Leste government. Post-hearing briefs from both parties were filed in August 2014. In January 2016, the Government of Timor-Leste and ConocoPhillips reached a settlement of several significant tax disputes. However, we await the Tribunal's decision with respect to certain unresolved matters.

**Long-Term Throughput Agreements and Take-or-Pay Agreements**
We have certain throughput agreements and take-or-pay agreements in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the company's business. The aggregate amounts of estimated payments under these various agreements are: 2016—$27 million; 2017—$27 million; 2018—$22 million; 2019—$7 million; 2020—$7 million; and 2021 and after—$80 million. Total payments under the agreements were $27 million in 2015 and $127 million in each of 2014 and 2013.

## Note 14—Derivative and Financial Instruments

We use futures, forwards, swaps and options in various markets to meet our customer needs and capture market opportunities. Our commodity business primarily consists of natural gas, crude oil, bitumen, LNG and natural gas liquids.

Our derivative instruments are held at fair value on our consolidated balance sheet. Where these balances have the right of setoff, they are presented on a net basis. Related cash flows are recorded as operating activities on our consolidated statement of cash flows. On our consolidated income statement, realized and unrealized gains and losses are recognized either on a gross basis if directly related to our physical business or a net basis if held for trading. Gains and losses related to contracts that meet and are designated with the normal purchase normal sale exception are recognized upon settlement. We generally apply this exception to eligible crude contracts. We do not use hedge accounting for our commodity derivatives.

The following table presents the gross fair values of our commodity derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

| | Millions of Dollars | |
|---|---|---|
| | **2015** | 2014 |
| **Assets** | | |
| Prepaid expenses and other current assets | $ **768** | 4,500 |
| Other assets | **60** | 157 |
| **Liabilities** | | |
| Other accruals | **754** | 4,426 |
| Other liabilities and deferred credits | **46** | 144 |

The gains (losses) from commodity derivatives incurred, and the line items where they appear on our consolidated income statement were:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| Sales and other operating revenues | $ | **231** | 523 | (160) |
| Other income | | **2** | 1 | 4 |
| Purchased commodities | | **(201)** | (458) | 139 |

The table below summarizes our material net exposures resulting from outstanding commodity derivative contracts:

| | Open Position Long/(Short) | |
|---|---|---|
| | **2015** | 2014 |
| **Commodity** | | |
| Natural gas and power (billions of cubic feet equivalent) | | |
| Fixed price | **(14)** | (11) |
| Basis | **(17)** | 18 |

**Foreign Currency Exchange Derivatives**
We have foreign currency exchange rate risk resulting from international operations. Our foreign currency exchange derivative activity primarily relates to managing our cash-related and foreign currency exchange rate exposures, such as firm commitments for capital programs or local currency tax payments, dividends, and cash returns from net investments in foreign affiliates. We do not elect hedge accounting on our foreign currency exchange derivatives.

The following table presents the gross fair values of our foreign currency exchange derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2015** | 2014 |
| **Assets** | | | |
| Prepaid expenses and other current assets | $ | **47** | 1 |
| **Liabilities** | | | |
| Other accruals | | **8** | 1 |

The (gains) losses from foreign currency exchange derivatives incurred, and the line item where they appear on our consolidated income statement were:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| Foreign currency transaction (gains) losses | $ | **(33)** | 3 | 4 |

We had the following net notional position of outstanding foreign currency exchange derivatives:

| | | In Millions Notional Currency | |
|---|---|---|---|
| | | **2015** | 2014 |
| **Foreign Currency Exchange Derivatives** | | | |
| Sell U.S. dollar, buy other currencies* | USD | **347** | 7 |
| Buy U.S. dollar, sell other currencies** | USD | **20** | 44 |
| Buy British pound, sell other currencies*** | GBP | **567** | 20 |

**Primarily Canadian dollar, Norwegian krone and British pound.*
***Primarily Canadian dollar and Norwegian krone.*
****Primarily Canadian dollar and euro.*

**Financial Instruments**
We have certain financial instruments with maturities based on our cash forecasts for the various currency pools we manage. The maturities of these investments may from time to time extend beyond 90 days. The types of financial instruments include:

- Time deposits: Interest bearing deposits placed with approved financial institutions.
- Money market funds: Short-term securities representing high-quality liquid debt and monetary instruments.
- Commercial paper: Unsecured promissory notes issued by a corporation, commercial bank, or government agency purchased at a discount, maturing at par.

These financial instruments appear in the "Cash and cash equivalents" line of our consolidated balance sheet if the maturities at the time we made the investments were 90 days or less. At December 31, we held the following financial instruments:

| | Millions of Dollars<br>Carrying Amount<br>Cash and Cash Equivalents | |
|---|---|---|
| | **2015** | 2014 |
| **Cash** | **$ 528** | 946 |
| **Money market funds** | **-** | 50 |
| **Time deposits** | | |
| Remaining maturities from 1 to 90 days | **1,840** | 3,726 |
| **Commercial paper** | | |
| Remaining maturities from 1 to 90 days | **-** | 340 |
| | **$ 2,368** | 5,062 |

**Credit Risk**
Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalents, over-the-counter (OTC) derivative contracts and trade receivables. Our cash equivalents are placed in high-quality commercial paper, money market funds, government debt securities and time deposits with major international banks and financial institutions.

The credit risk from our OTC derivative contracts, such as forwards and swaps, derives from the counterparty to the transaction. Individual counterparty exposure is managed within predetermined credit limits and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant nonperformance. We also use futures, swaps and option contracts that have a negligible credit risk because these trades are cleared with an exchange clearinghouse and subject to mandatory margin requirements until settled; however, we are exposed to the credit risk of those exchange brokers for receivables arising from daily margin cash calls, as well as for cash deposited to meet initial margin requirements.

Our trade receivables result primarily from our petroleum operations and reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less, and we continually monitor this exposure and the creditworthiness of the counterparties. We do not generally require collateral to limit the exposure to loss; however, we will sometimes use letters of credit, prepayments, and master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to us, as these agreements permit the amounts owed by us or owed to others to be offset against amounts due us.

Certain of our derivative instruments contain provisions that require us to post collateral if the derivative exposure exceeds a threshold amount. We have contracts with fixed threshold amounts and other contracts with variable threshold amounts that are contingent on our credit rating. The variable threshold amounts typically decline for lower credit ratings, while both the variable and fixed threshold amounts typically revert to zero if we fall below investment grade. Cash is the primary collateral in all contracts; however, many also permit us to post letters of credit as collateral, such as transactions administered through the New York Mercantile Exchange.

The aggregate fair value of all derivative instruments with such credit risk-related contingent features that were in a liability position on December 31, 2015 and December 31, 2014, was $158 million and $150 million, respectively. For these instruments, $2 million of collateral was posted as of December 31, 2015, and no collateral was posted as of December 31, 2014. If our credit rating had been lowered one level from its “A” rating (per Standard and Poor’s) on December 31, 2015, we would be required to post no additional collateral to our counterparties. If we had been downgraded below investment grade, we would be required to post $156 million of additional collateral, either with cash or letters of credit.

## Note 15—Fair Value Measurement

We carry a portion of our assets and liabilities at fair value that are measured at a reporting date using an exit price (i.e., the price that would be received to sell an asset or paid to transfer a liability) and disclosed according to the quality of valuation inputs under the following hierarchy:

- Level 1: Quoted prices (unadjusted) in an active market for identical assets or liabilities.
- Level 2: Inputs other than quoted prices that are directly or indirectly observable.
- Level 3: Unobservable inputs that are significant to the fair value of assets or liabilities.

The classification of an asset or liability is based on the lowest level of input significant to its fair value. Those that are initially classified as Level 3 are subsequently reported as Level 2 when the fair value derived from unobservable inputs is inconsequential to the overall fair value, or if corroborated market data becomes available. Assets and liabilities that are initially reported as Level 2 are subsequently reported as Level 3 if corroborated market data is no longer available. Transfers occur at the end of the reporting period. There were no material transfers in or out of Level 1 during 2015 and 2014.

### Recurring Fair Value Measurement

Financial assets and liabilities reported at fair value on a recurring basis primarily include commodity derivatives and certain investments to support nonqualified deferred compensation plans. The deferred compensation investments are measured at fair value using unadjusted prices available from national securities exchanges; therefore, these assets are categorized as Level 1 in the fair value hierarchy. Level 1 derivative assets and liabilities primarily represent exchange-traded futures and options that are valued using unadjusted prices available from the underlying exchange. Level 2 derivative assets and liabilities primarily represent OTC swaps, options and forward purchase and sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data. Level 3 derivative assets and liabilities consist of OTC swaps, options and forward purchase and sale contracts where a significant portion of fair value is calculated from underlying market data that is not readily available. The derived value uses industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management's best estimate of fair value. Level 3 activity was not material for all periods presented.

The following table summarizes the fair value hierarchy for gross financial assets and liabilities (i.e., unadjusted where the right of setoff exists for commodity derivatives accounted for at fair value on a recurring basis):

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | **December 31, 2015** | | | | December 31, 2014 | | | |
| | | **Level 1** | **Level 2** | **Level 3** | **Total** | Level 1 | Level 2 | Level 3 | Total |
| **Assets** | | | | | | | | | |
| Deferred compensation investments | **$** | **21** | **-** | **-** | **21** | 297 | - | - | 297 |
| Commodity derivatives | | **516** | **242** | **70** | **828** | 4,221 | 361 | 75 | 4,657 |
| Total assets | **$** | **537** | **242** | **70** | **849** | 4,518 | 361 | 75 | 4,954 |
| **Liabilities** | | | | | | | | | |
| Commodity derivatives | **$** | **515** | **273** | **12** | **800** | 4,200 | 354 | 16 | 4,570 |
| Total liabilities | **$** | **515** | **273** | **12** | **800** | 4,200 | 354 | 16 | 4,570 |

The following table summarizes those commodity derivative balances subject to the right of setoff as presented on our consolidated balance sheet. We have elected to offset the recognized fair value amounts for multiple derivative instruments executed with the same counterparty in our financial statements when a legal right of offset exists.

| | Millions of Dollars | | | | | | |
|---|---|---|---|---|---|---|---|
| | | Gross Amounts Recognized | Gross Amounts Offset | Net Amounts Presented | Cash Collateral | Gross Amounts without Right of Setoff | Net Amounts |
| **December 31, 2015** | | | | | | | |
| Assets | **$** | **828** | **600** | **228** | **-** | **8** | **220** |
| Liabilities | | **800** | **600** | **200** | **1** | **11** | **188** |
| December 31, 2014 | | | | | | | |
| Assets | $ | 4,657 | 4,352 | 305 | 8 | 28 | 269 |
| Liabilities | | 4,570 | 4,352 | 218 | 4 | 22 | 192 |

At December 31, 2015 and December 31, 2014, we did not present any amounts gross on our consolidated balance sheet where we had the right of setoff.

**Non-Recurring Fair Value Measurement**

The following table summarizes the fair value hierarchy by major category for assets accounted for at fair value on a non-recurring basis:

| | Millions of Dollars | | |
|---|---|---|---|
| | | Fair Value Measurements Using | |
| | Fair Value* | Level 3 Inputs | Before-Tax Loss |
| **Year ended December 31, 2015** | | | |
| Net PP&E (held for use) | **$ 440** | **440** | **681** |
| Net PP&E (unproved property) | **104** | **104** | **240** |
| Equity method investments | **10,210** | **10,210** | **1,507** |
| | | | |
| Year ended December 31, 2014 | | | |
| Net PP&E (held for use) | $ 87 | 87 | 756 |
| Net PP&E (unproved property) | 39 | 39 | 158 |

**Represents the fair value at the time of the impairment.*

*Net PP&E (held for use)*
Net PP&E held for use is comprised of various producing properties impaired to their individual fair values less costs to sell. The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges and pricing service companies, costs, and a discount rate believed to be consistent with those used by principal market participants.

*Net PP&E (unproved property)*
Net PP&E unproved property is comprised of unproved leaseholds impaired to our best estimate of sales value less costs to sell.

*Equity Method Investments*
Certain equity method investments, primarily our investment in APLNG, were determined to have fair values below their carrying amounts, and the impairments were considered to be other than temporary. For additional information, see Note 7—Investments, Loans and Long-Term Receivables.

**Reported Fair Values of Financial Instruments**
We used the following methods and assumptions to estimate the fair value of financial instruments:

- Cash and cash equivalents: The carrying amount reported on the balance sheet approximates fair value.
- Accounts and notes receivable (including long-term and related parties): The carrying amount reported on the balance sheet approximates fair value. The valuation technique and methods used to estimate the fair value of the current portion of fixed-rate related party loans is consistent with Loans and advances—related parties.
- Loans and advances—related parties: The carrying amount of floating-rate loans approximates fair value. The fair value of fixed-rate loan activity is measured using market observable data and is categorized as Level 2 in the fair value hierarchy. See Note 7—Investments, Loans and Long-Term Receivables, for additional information.
- Accounts payable (including related parties) and floating-rate debt: The carrying amount of accounts payable and floating-rate debt reported on the balance sheet approximates fair value.
- Fixed-rate debt: The estimated fair value of fixed-rate debt is measured using prices available from a pricing service that is corroborated by market data; therefore, these liabilities are categorized as Level 2 in the fair value hierarchy.

The following table summarizes the net fair value of financial instruments (i.e., adjusted where the right of setoff exists for commodity derivatives):

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | Carrying Amount | | Fair Value | |
| | **2015** | 2014 | **2015** | 2014 |
| **Financial assets** | | | | |
| Deferred compensation investments | $ **21** | 297 | **21** | 297 |
| Commodity derivatives | **228** | 297 | **228** | 297 |
| Total loans and advances—related parties | **808** | 913 | **808** | 913 |
| **Financial liabilities** | | | | |
| Total debt, excluding capital leases | **24,062** | 21,707 | **24,785** | 25,191 |
| Commodity derivatives | **199** | 214 | **199** | 214 |

<u>*Deferred compensation investments*</u>
In May 2015, we liquidated certain deferred compensation investments for proceeds of $267 million, which is included in the "Other" line within "Cash Flows From Investing Activities" on our consolidated statement of cash flows.

<u>*Commodity derivatives*</u>
At December 31, 2015, commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $1 million of rights to reclaim cash collateral, respectively. At December 31, 2014, commodity derivative assets and liabilities appear net of $8 million of obligations to return cash collateral and $4 million of rights to reclaim cash collateral, respectively.

## Note 16—Equity

### Common Stock
The changes in our shares of common stock, as categorized in the equity section of the balance sheet, were:

| | Shares | | |
|---|---|---|---|
| | **2015** | 2014 | 2013 |
| **Issued** | | | |
| Beginning of year | **1,773,583,368** | 1,768,169,906 | 1,762,247,949 |
| Distributed under benefit plans | **4,643,020** | 5,413,462 | 5,921,957 |
| End of year | **1,778,226,388** | 1,773,583,368 | 1,768,169,906 |

### Preferred Stock
We have authorized 500 million shares of preferred stock, par value $.01 per share, none of which was issued or outstanding at December 31, 2015 or 2014.

### Noncontrolling Interests
At December 31, 2015 and 2014, we had $320 million and $362 million outstanding, respectively, of equity in less-than-wholly owned consolidated subsidiaries held by noncontrolling interest owners. For both periods, the amounts were related to the Darwin LNG and Bayu-Darwin Pipeline operating joint ventures we control.

**Note 17—Non-Mineral Leases**

The company primarily leases drilling equipment and office buildings, as well as ocean transport vessels, tugboats, barges, corporate aircraft, computers and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices, as well as renewal options and/or options to purchase the leased property for the fair market value at the end of the lease term. There are no significant restrictions imposed on us by the leasing agreements with regard to dividends, asset dispositions or borrowing ability. For additional information on leased assets under capital leases, see Note 11—Debt.

At December 31, 2015, future minimum rental payments due under noncancelable leases were:

| | Millions of Dollars |
|---|---|
| 2016 | $ 671 |
| 2017 | 360 |
| 2018 | 215 |
| 2019 | 156 |
| 2020 | 374 |
| Remaining years | 381 |
| Total | 2,157 |
| Less: income from subleases | (9) |
| Net minimum operating lease payments | $ 2,148 |

Operating lease rental expense for the years ended December 31 was:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2015** | 2014 | 2013 |
| Total rentals | **$ 432** | 474 | 317 |
| Less: sublease rentals | **(9)** | (10) | (12) |
| | **$ 423** | 464 | 305 |

## Note 18—Employee Benefit Plans

### Pension and Postretirement Plans

An analysis of the projected benefit obligations for our pension plans and accumulated benefit obligations for our postretirement health and life insurance plans follows:

| | | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|---|
| | | Pension Benefits | | | | Other Benefits | |
| | | **2015** | | 2014 | | **2015** | 2014 |
| | | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| **Change in Benefit Obligation** | | | | | | | |
| Benefit obligation at January 1 | **$** | **4,387** | **3,984** | 3,954 | 3,583 | **716** | 682 |
| Service cost | | **138** | **124** | 124 | 109 | **4** | 3 |
| Interest cost | | **161** | **135** | 165 | 166 | **22** | 29 |
| Plan participant contributions | | **-** | **5** | - | 6 | **21** | 21 |
| Plan amendments | | **-** | **-** | - | - | **(303)** | - |
| Actuarial (gain) loss | | **(212)** | **(442)** | 477 | 598 | **(49)** | 53 |
| Benefits paid | | **(729)** | **(162)** | (333) | (122) | **(63)** | (70) |
| Curtailment | | **27** | **(43)** | - | - | **8** | - |
| Recognition of termination benefits | | **-** | **68** | - | - | **-** | - |
| Foreign currency exchange rate change | | **-** | **(348)** | - | (356) | **(4)** | (2) |
| Benefit obligation at December 31* | **$** | **3,772** | **3,321** | 4,387 | 3,984 | **352** | 716 |
| **Accumulated benefit obligation portion of above at December 31:* | ***$*** | ***3,573*** | ***2,953*** | *3,957* | *3,111* | | |
| **Change in Fair Value of Plan Assets** | | | | | | | |
| Fair value of plan assets at January 1 | **$** | **3,266** | **3,278** | 3,092 | 3,132 | **-** | - |
| Actual return on plan assets | | **(4)** | **96** | 234 | 410 | **-** | - |
| Company contributions | | **73** | **120** | 273 | 203 | **42** | 49 |
| Plan participant contributions | | **-** | **5** | - | 6 | **21** | 21 |
| Benefits paid | | **(729)** | **(162)** | (333) | (122) | **(63)** | (70) |
| Foreign currency exchange rate change | | **-** | **(274)** | - | (351) | **-** | - |
| Fair value of plan assets at December 31 | **$** | **2,606** | **3,063** | 3,266 | 3,278 | **-** | - |
| **Funded Status** | **$** | **(1,166)** | **(258)** | (1,121) | (706) | **(352)** | (716) |

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Pension Benefits | | | | Other Benefits | |
| | **2015** | | 2014 | | **2015** | 2014 |
| | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| **Amounts Recognized in the Consolidated Balance Sheet at December 31** | | | | | | |
| Noncurrent assets | $ **-** | **175** | - | 13 | **-** | - |
| Current liabilities | **(99)** | **(34)** | (26) | (9) | **(45)** | (49) |
| Noncurrent liabilities | **(1,067)** | **(399)** | (1,095) | (710) | **(307)** | (667) |
| Total recognized | $ **(1,166)** | **(258)** | (1,121) | (706) | **(352)** | (716) |
| **Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31** | | | | | | |
| Discount rate | **4.50 %** | **3.95** | 3.80 | 3.55 | **3.90** | 4.15 |
| Rate of compensation increase | **4.00** | **4.05** | 4.75 | 4.35 | **-** | - |
| **Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31** | | | | | | |
| Discount rate | **4.00 %** | **3.55** | 4.40 | 4.75 | **4.05** | 4.45 |
| Expected return on plan assets | **7.00** | **5.40** | 7.00 | 5.75 | **-** | - |
| Rate of compensation increase | **4.75** | **4.35** | 4.75 | 4.60 | **-** | - |

For both U.S. and international pensions, the overall expected long-term rate of return is developed from the expected future return of each asset class, weighted by the expected allocation of pension assets to that asset class. We rely on a variety of independent market forecasts in developing the expected rate of return for each class of assets.

Included in accumulated other comprehensive income (loss) at December 31 were the following before-tax amounts that had not been recognized in net periodic benefit cost:

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Pension Benefits | | | | Other Benefits | |
| | **2015** | | 2014 | | **2015** | 2014 |
| | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| Unrecognized net actuarial (gain) loss | $ **773** | **273** | 1,146 | 852 | **(18)** | 25 |
| Unrecognized prior service cost (credit) | **9** | **(30)** | 16 | (43) | **(292)** | (4) |

| | | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|---|
| | | Pension Benefits | | | | Other Benefits | |
| | | **2015** | | 2014 | | **2015** | 2014 |
| | | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| **Sources of Change in Other Comprehensive Income (Loss)** | | | | | | | |
| Net gain (loss) arising during the period | **$** | **61** | **490** | (456) | (331) | **41** | (53) |
| Amortization of (gain) loss included in income (loss)* | | **312** | **89** | 77 | 57 | **2** | (3) |
| Net change during the period | **$** | **373** | **579** | (379) | (274) | **43** | (56) |
| | | | | | | | |
| Prior service credit (cost) arising during the period | **$** | **-** | **(2)** | - | (3) | **303** | - |
| Amortization of prior service cost (credit) included in income (loss) | | **7** | **(11)** | 6 | (8) | **(15)** | (4) |
| Net change during the period | **$** | **7** | **(13)** | 6 | (11) | **288** | (4) |

**Includes settlement losses recognized in 2015.*

During the year ended December 31, 2015, there were amendments to the U.S. other postretirement benefit plan. The benefit obligation decreased by $303 million for changes in the plan made to retiree medical benefits. The $303 million decrease consists of $149 million related to the discontinuation of all company premium cost-sharing contributions to the post-65 retiree medical plan after December 31, 2025, $91 million related to updated cost sharing assumption changes for retirees, $49 million associated with excluding employees and retirees of Phillips 66 who were not enrolled in a ConocoPhillips retiree medical plan as of July 1, 2015, and $14 million associated with new participants in the post-65 retiree medical plan after December 31, 2015 no longer being eligible for any company premium cost-sharing contributions. The $303 million decrease in the benefit obligation resulted in a corresponding decrease in other comprehensive loss.

Included in accumulated other comprehensive income (loss) at December 31, 2015, were the following before-tax amounts that are expected to be amortized into net periodic benefit cost during 2016:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | Pension Benefits | | Other Benefits |
| | | U.S. | Int'l. | |
| Unrecognized net actuarial (gain) loss | $ | 78 | 30 | (2) |
| Unrecognized prior service cost (credit) | | 5 | (6) | (34) |

For our tax-qualified pension plans with projected benefit obligations in excess of plan assets, the projected benefit obligation, the accumulated benefit obligation, and the fair value of plan assets were $5,720 million, $5,314 million, and $4,759 million, respectively, at December 31, 2015, and $7,584 million, $6,503 million, and $6,446 million, respectively, at December 31, 2014.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $639 million and $564 million, respectively, at December 31, 2015, and were $703 million and $482 million, respectively, at December 31, 2014.

The components of net periodic benefit cost of all defined benefit plans are presented in the following table:

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Pension Benefits | | | | | | Other Benefits | | |
| | **2015** | | 2014 | | 2013 | | **2015** | 2014 | 2013 |
| | **U.S.** | **Int'l.** | U.S. | Int'l. | U.S. | Int'l. | | | |
| **Components of Net Periodic Benefit Cost** | | | | | | | | | |
| Service cost | **$ 138** | **124** | 124 | 109 | 138 | 102 | **4** | 3 | 3 |
| Interest cost | **161** | **135** | 165 | 166 | 143 | 145 | **22** | 29 | 26 |
| Expected return on plan assets | **(201)** | **(164)** | (213) | (181) | (186) | (160) | **-** | - | - |
| Amortization of prior service cost (credit) | **6** | **(7)** | 6 | (8) | 6 | (7) | **(17)** | (4) | (4) |
| Recognized net actuarial loss (gain) | **115** | **82** | 77 | 57 | 151 | 73 | **2** | (3) | 3 |
| Settlements | **197** | **7** | - | - | 67 | - | **-** | - | - |
| Curtailment (gain) loss | **35** | **(4)** | - | - | - | - | **2** | - | - |
| Net periodic benefit cost | **$ 451** | **173** | 159 | 143 | 319 | 153 | **13** | 25 | 28 |

We recognized pension settlement losses of $204 million in 2015 and $67 million in 2013 as lump-sum benefit payments from certain U.S. and international pension plans exceeded the sum of service and interest costs for those plans and led to recognition of settlement losses.

As part of the 2015 restructuring program, we concluded that actions taken during the year ended December 31, 2015, resulted in a significant reduction of future services of active employees in the U.S. qualified pension plan, a U.S. nonqualified supplemental retirement plan, certain international qualified and nonqualified pension plans, and the U.S. other postretirement benefit plan. As a result, we recognized an increase in the benefit obligation and a proportionate share of prior service cost from other comprehensive income (loss) as curtailment losses of $33 million during the year ended December 31, 2015.

Also as part of the 2015 restructuring program in the U.S. and Europe, we recognized expense for special termination benefits of $124 million during the year ended December 31, 2015, consisting of $46 million in the U.S. and $78 million in Europe (including related social security tax). Approximately 62 percent of the Europe amount is recoverable from joint venture partners.

In determining net pension and other postretirement benefit costs, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. For net actuarial gains and losses, we amortize 10 percent of the unamortized balance each year.

We have multiple nonpension postretirement benefit plans for health and life insurance. The health care plans are contributory and subject to various cost sharing features, with participant and company contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the U.S. pre-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 6.75 percent in 2016 that declines to 5 percent by 2023. The measurement of the U.S. post-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 3 percent in 2016 that increases to 5 percent by 2018. A one-percentage-point change in the assumed health care cost trend rate would be immaterial to ConocoPhillips.

**Plan Assets**—We follow a policy of broadly diversifying pension plan assets across asset classes, investment managers and individual holdings. As a result, our plan assets have no significant concentrations of credit risk. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. The target allocations for plan assets are 58 percent equity securities, 36 percent debt securities and 6 percent real estate. Generally, the plan investments are publicly traded, therefore minimizing liquidity risk in the portfolio.

The following is a description of the valuation methodologies used for the pension plan assets. There have been no changes in the methodologies used at December 31, 2015 and 2014.

- Fair values of equity securities and government debt securities categorized in Level 1 are primarily based on quoted market prices in active markets for identical assets and liabilities.
- Fair values of corporate debt securities, agency and mortgage-backed securities and government debt securities categorized in Level 2 are estimated using recently executed transactions and quoted market prices for similar assets and liabilities in active markets and for identical assets and liabilities in markets that are not active. If there have been no market transactions in a particular fixed income security, its fair value is calculated by pricing models that benchmark the security against other securities with actual market prices. When observable quoted market prices are not available, fair value is based on pricing models that use something other than actual market prices (e.g., observable inputs such as benchmark yields, reported trades and issuer spreads for similar securities), and these securities are categorized in Level 3 of the fair value hierarchy.
- Fair values of investments in common/collective trusts are determined by the issuer of each fund based on the fair value of the underlying assets.
- Fair values of mutual funds are based on quoted market prices, which represent the net asset value of shares held.
- Cash is valued at cost, which approximates fair value. Fair values of international cash equivalents categorized in Level 2 are valued using observable yield curves, discounting and interest rates. U.S. cash balances held in the form of short-term fund units that are redeemable at the measurement date are categorized as Level 2.
- Fair values of exchange-traded derivatives classified in Level 1 are based on quoted market prices. For other derivatives classified in Level 2, the values are generally calculated from pricing models with market input parameters from third-party sources.
- Private equity funds are valued at net asset value as determined by the issuer based on the fair value of the underlying assets.
- Fair values of insurance contracts are valued at the present value of the future benefit payments owed by the insurance company to the plans' participants.
- Fair values of real estate investments are valued using real estate valuation techniques and other methods that include reference to third-party sources and sales comparables where available.
- A portion of U.S. pension plan assets is held as a participating interest in an insurance annuity contract, which is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract. The participating interest is classified as Level 3 in the fair value hierarchy as the fair value is determined via a combination of quoted market prices, recently executed transactions, and an actuarial present value computation for contract obligations. At December 31, 2015, the participating interest in the annuity contract was valued at $125 million and consisted of $305 million in debt securities, less $180 million for the accumulated benefit obligation covered by the contract. At December 31, 2014, the participating interest in the annuity contract was valued at $116 million and consisted of $328 million in debt securities, less $212 million for the accumulated benefit obligation covered by the contract. The net change from 2014 to 2015 is due to a decrease in the fair value of the underlying investments of $23 million and a decrease in the present value of the contract obligation of $32 million. The participating interest is not available for meeting general pension benefit obligations in the near term. No future company contributions are required and no new benefits are being accrued under this insurance annuity contract.

The fair values of our pension plan assets at December 31, by asset class were as follows:

| | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | U.S. | | | | International | | | |
| | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
| **2015** | | | | | | | | |
| Equity Securities | | | | | | | | |
| U.S. | **$ 777** | **3** | **2** | **782** | **609** | **-** | **-** | **609** |
| International | **485** | **-** | **-** | **485** | **450** | **-** | **-** | **450** |
| Common/collective trusts | **-** | **569** | **-** | **569** | **-** | **214** | **-** | **214** |
| Mutual funds | **-** | **-** | **-** | **-** | **234** | **106** | **-** | **340** |
| Debt Securities | | | | | | | | |
| Government | **85** | **56** | **-** | **141** | **493** | **-** | **-** | **493** |
| Corporate | **-** | **331** | **17** | **348** | **-** | **172** | **-** | **172** |
| Agency and mortgage-backed securities | **-** | **80** | **-** | **80** | **-** | **36** | **-** | **36** |
| Common/collective trusts | **-** | **-** | **-** | **-** | **-** | **406** | **-** | **406** |
| Mutual funds | **-** | **-** | **-** | **-** | **136** | **-** | **-** | **136** |
| Cash and cash equivalents | **-** | **60** | **-** | **60** | **46** | **10** | **-** | **56** |
| Derivatives | **-** | **(7)** | **-** | **(7)** | **(26)** | **-** | **-** | **(26)** |
| Real estate | **-** | **-** | **63** | **63** | **-** | **-** | **169** | **169** |
| Total* | **$ 1,347** | **1,092** | **82** | **2,521** | **1,942** | **944** | **169** | **3,055** |

**Excludes the participating interest in the insurance annuity contract with a net asset value of $125 million and net payables related to security transactions of $32 million.*

| | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|---|---|---|---|
| 2014 | | | | | | | | |
| Equity Securities | | | | | | | | |
| U.S. | $ 1,039 | 2 | 8 | 1,049 | 628 | - | - | 628 |
| International | 671 | - | - | 671 | 445 | - | - | 445 |
| Common/collective trusts | - | 542 | - | 542 | - | 227 | - | 227 |
| Mutual funds | - | - | - | - | 241 | 97 | - | 338 |
| Debt Securities | | | | | | | | |
| Government | 132 | 75 | - | 207 | 624 | - | - | 624 |
| Corporate | - | 426 | 4 | 430 | - | 166 | - | 166 |
| Agency and mortgage-backed securities | - | 115 | - | 115 | - | 46 | 1 | 47 |
| Common/collective trusts | - | - | - | - | - | 396 | - | 396 |
| Mutual funds | - | - | - | - | 167 | - | - | 167 |
| Cash and cash equivalents | - | 67 | - | 67 | 50 | 18 | - | 68 |
| Private equity funds | - | - | - | - | - | - | 1 | 1 |
| Derivatives | 5 | (3) | - | 2 | (4) | - | - | (4) |
| Real estate | - | - | 55 | 55 | - | - | 166 | 166 |
| Total* | $ 1,847 | 1,224 | 67 | 3,138 | 2,151 | 950 | 168 | 3,269 |

**Excludes the participating interest in the insurance annuity contract with a net asset value of $116 million and net receivables related to security transactions of $21 million.*

Level 3 activity was not material for all periods.

Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code of 1986, as amended. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2016, we expect to contribute approximately $220 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $190 million to our international qualified and nonqualified pension and postretirement benefit plans.

The following benefit payments, which are exclusive of amounts to be paid from the insurance annuity contract and which reflect expected future service, as appropriate, are expected to be paid:

| | Millions of Dollars | | |
|---|---|---|---|
| | Pension Benefits | | Other Benefits |
| | U.S. | Int'l. | |
| 2016 | $ 414 | 150 | 45 |
| 2017 | 347 | 144 | 43 |
| 2018 | 335 | 140 | 41 |
| 2019 | 335 | 143 | 39 |
| 2020 | 338 | 149 | 38 |
| 2021–2025 | 1,544 | 858 | 158 |

**Severance Accrual**
As a result of the current business environment's impact on our operating and capital plans, a reduction in our overall employee workforce occurred during 2015. Severance accruals of $306 million were recorded in 2015. The following table summarizes our severance accrual activity for the year ended December 31, 2015:

| | Millions of Dollars |
|---|---|
| Balance at December 31, 2014 | $ 61 |
| Accruals | **306** |
| Accrual reversals | **(3)** |
| Benefit payments | **(200)** |
| Foreign currency translation adjustments | **(8)** |
| Balance at December 31, 2015 | **$ 156** |

Of the remaining balance at December 31, 2015, $121 million is classified as short-term.

**Defined Contribution Plans**
Most U.S. employees are eligible to participate in the ConocoPhillips Savings Plan (CPSP). Employees can deposit up to 75 percent of their eligible pay, subject to statutory limits, in the CPSP to a choice of approximately 35 investment funds. In 2015, employees who participate in the CPSP and contribute 1 percent of their eligible pay receive a 9 percent company cash match, subject to certain limitations. Starting in 2016, employees who participate in the CPSP and contribute 1 percent of their eligible pay receive a 6 percent company cash match with a potential company discretionary cash contribution of up to 6 percent. Company contributions charged to expense related to continuing and discontinued operations for the CPSP and predecessor plans were $103 million in 2015, $116 million in 2014, and $101 million in 2013.

In 1990, the Long-Term Stock Savings Plan of Phillips Petroleum Company (subsequently the stock savings feature of the CPSP) borrowed funds that were used to purchase previously unissued shares of company common stock. Since the company guaranteed the CPSP's borrowings, the unpaid balance was reported as a liability of the company and unearned compensation was shown as a reduction of common stockholders' equity. Dividends on all shares were charged against retained earnings. The debt was serviced by the CPSP from company contributions and dividends received on certain shares of common stock held by the plan, including all unallocated shares. The shares held by the stock savings feature of the CPSP were released for allocation to participant accounts based on debt service payments on CPSP borrowings. In 2012, the final debt service payment was made and all remaining unallocated shares were released for allocation to participant accounts. The total number of allocated CPSP stock savings feature shares as of December 31, 2015 and 2014, were 7,243,832 and 8,198,873, respectively.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense related to continuing and discontinued operations recognized for these international plans was approximately $55 million in 2015, $66 million in 2014 and $60 million in 2013.

**Share-Based Compensation Plans**
The 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (the Plan) was approved by shareholders in May 2014. Over its 10-year life, the Plan allows the issuance of up to 79 million shares of our common stock for compensation to our employees and directors; however, as of the effective date of the Plan, (i) any shares of common stock available for future awards under the prior plans and (ii) any shares of common stock represented by awards granted under the prior plans that are forfeited, expire or are cancelled without delivery of shares of common stock or which result in the forfeiture of shares of common stock back to the company shall be available for awards under the Plan, and no new awards shall be granted under the prior plans. Of the 79 million shares available for issuance under the Plan, no more than 40 million shares of common stock are available for incentive stock options. The Human Resources and Compensation Committee of our Board of Directors is authorized to determine the types, terms, conditions, and limitations of awards granted. Awards may be granted in the form of, but not limited to, stock options, restricted stock units, and performance share units to employees and nonemployee directors who contribute to the company's continued success and profitability.

Total share-based compensation expense is measured using the grant date fair value for our equity-classified awards and the settlement date fair value for our liability-classified awards. We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award); or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement, but not less than six months, as this is the minimum period of time required for an award to not be subject to forfeiture. Our share-based compensation programs generally provide accelerated vesting (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. Some of our share-based awards vest ratably (i.e., portions of the award vest at different times) while some of our awards cliff vest (i.e., all of the award vests at the same time). We recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

**Stock Options**—Stock options granted under the provisions of the Plan and prior plans permit purchase of our common stock at exercise prices equivalent to the average market price of ConocoPhillips common stock on the date the options were granted. The options have terms of 10 years and generally vest ratably, with one-third of the options awarded vesting and becoming exercisable on each anniversary date following the date of grant. Options awarded to certain employees already eligible for retirement vest within six months of the grant date, but those options do not become exercisable until the end of the normal vesting period.

**Compensation Expense**—Total share-based compensation expense recognized in income (loss) related to continuing and discontinued operations and the associated tax benefit for the years ended December 31 were as follows:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2015** | 2014 | 2013 |
| Compensation cost | $ **362** | 358 | 308 |
| Tax benefit | **123** | 125 | 109 |

The fair market values of the options granted over the past three years were measured on the date of grant using the Black-Scholes-Merton option-pricing model. The weighted-average assumptions used were as follows:

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Assumptions used | | | |
| Risk-free interest rate | **1.79 %** | 1.86 | 1.09 |
| Dividend yield | **4.00 %** | 4.00 | 4.00 |
| Volatility factor | **23.32 %** | 25.31 | 28.95 |
| Expected life (years) | **5.79** | 6.12 | 5.95 |

There were no ranges in the assumptions used to determine the fair market values of our options granted over the past three years.

Due to the separation of our Downstream businesses in 2012, expected volatility for grants of options in 2014 and 2013 was based on a three-year average historical stock price volatility of a group of peer companies. We believe our historical volatility for periods prior to the separation of our Downstream businesses is no longer relevant in estimating expected volatility. For 2015, expected volatility was based on the weighted average blend of the company's historical stock price volatility from May 1, 2012 (the date of separation of our Downstream businesses) through the stock option grant date and the average historical stock price volatility of a group of peer companies for the expected term of the options.

The following summarizes our stock option activity for the year ended December 31, 2015:

| | Options | Weighted-Average Exercise Price | Weighted-Average Grant Date Fair Value | Millions of Dollars Aggregate Intrinsic Value |
|---|---|---|---|---|
| Outstanding at December 31, 2014 | 17,117,871 | $ 52.61 | | $ 284 |
| Granted | **3,873,700** | **69.25** | **$ 9.54** | |
| Exercised | **(548,707)** | **42.11** | | **10** |
| Forfeited | **(258,010)** | **69.20** | | |
| Expired or cancelled | **(44)** | **23.37** | | |
| **Outstanding at December 31, 2015** | **20,184,810** | **$ 55.88** | | **$ 42** |
| **Vested at December 31, 2015** | **16,650,347** | **$ 53.66** | | **$ 42** |
| **Exercisable at December 31, 2015** | **13,192,751** | **$ 50.34** | | **$ 42** |

The weighted-average remaining contractual term of outstanding options, vested options and exercisable options at December 31, 2015, was 5.84 years, 5.27 years and 4.43 years, respectively. The weighted-average grant date fair value of stock option awards granted during 2014 and 2013 was $10.17 and $9.90, respectively. The aggregate intrinsic value of options exercised during 2014 and 2013 was $89 million and $95 million, respectively.

During 2015, we received $23 million in cash and realized a tax benefit related to both continuing and discontinued operations of $16 million from the exercise of options. At December 31, 2015, the remaining unrecognized compensation expense from unvested options was $16 million, which will be recognized over a weighted-average period of 1.22 years, the longest period being 2.13 years.

**Stock Unit Program**—Generally, restricted stock units are granted annually under the provisions of the Plan. Restricted stock units granted prior to 2013 generally vest ratably in three equal annual installments beginning on the third anniversary of the grant date. Beginning in 2013, restricted stock units granted will vest in an aggregate installment on the third anniversary of the grant date. In addition, beginning in 2012, restricted stock units granted under the Plan for a variable long-term incentive program vest ratably in three equal annual installments beginning on the first anniversary of the grant date. Restricted stock units are also granted ad hoc to attract or retain key personnel, and the terms and conditions under which these restricted stock units vest vary by award. Upon vesting, the restricted stock units are settled by issuing one share of ConocoPhillips common stock per unit. Units awarded to retirement eligible employees vest six months from the grant date; however, those units are not issued as common stock until the earlier of separation from the company or the end of the regularly scheduled vesting period. Until issued as stock, most recipients of the restricted stock units receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. The grant date fair market value of these restricted stock units is deemed equal to the average ConocoPhillips stock price on the grant date. The grant date fair market value of units that do not receive a dividend equivalent while unvested is deemed equal to the average ConocoPhillips stock price on the grant date, less the net present value of the dividends that will not be received.

The following summarizes our stock unit activity for the year ended December 31, 2015:

| | | Weighted-Average | Millions of Dollars |
|---|---|---|---|
| | Stock Units | Grant Date Fair Value | Total Fair Value |
| Outstanding at December 31, 2014 | 11,782,856 | $ 55.75 | |
| Granted | **3,455,150** | **65.40** | |
| Forfeited | **(660,298)** | **63.11** | |
| Issued | **(5,399,543)** | | **$ 316** |
| **Outstanding at December 31, 2015** | **9,178,165** | **$ 59.80** | |
| **Not Vested at December 31, 2015** | **6,289,931** | **$ 59.87** | |

At December 31, 2015, the remaining unrecognized compensation cost from the unvested units was $155 million, which will be recognized over a weighted-average period of 1.53 years, the longest period being 2.67 years. The weighted-average grant date fair value of stock unit awards granted during 2014 and 2013 was $62.72 and $57.99, respectively. The total fair value of stock units issued during 2014 and 2013 was $256 million and $245 million, respectively.

**Performance Share Program**—Under the Plan, we also annually grant restricted performance share units (PSUs) to senior management. These PSUs are authorized three years prior to their effective grant date (the performance period). Compensation expense is initially measured using the average fair market value of ConocoPhillips common stock and is subsequently adjusted, based on changes in the ConocoPhillips stock price through the end of each subsequent reporting period, through the grant date for stock-settled awards and the settlement date for cash-settled awards.

*Stock-Settled*

For performance periods beginning before 2009, PSUs do not vest until the employee becomes eligible for retirement by reaching age 55 with five years of service, and restrictions do not lapse until the employee separates from the company. With respect to awards for performance periods beginning in 2009 through 2012, PSUs do not vest until the earlier of the date the employee becomes eligible for retirement by reaching age 55 with five years of service or five years after the grant date of the award, and restrictions do not lapse until the earlier of the employee's separation from the company or five years after the grant date (although recipients can elect to defer the lapsing of restrictions until separation). We recognize compensation expense for these awards beginning on the grant date and ending on the date the PSUs are scheduled to vest. Since these awards are authorized three years prior to the grant date, for employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Until issued as stock, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. Beginning in 2013, PSUs authorized for future grants will vest, absent employee election to defer, upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending on the conclusion of the performance period. PSUs are settled by issuing one share of ConocoPhillips common stock per unit.

The following summarizes our stock-settled Performance Share Program activity for the year ended December 31, 2015:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2014 | 4,651,244 | $ 51.75 | |
| Granted | **59,807** | **69.25** | |
| Issued | **(440,829)** | | **$ 25** |
| **Outstanding at December 31, 2015** | **4,270,222** | **$ 51.95** | |
| **Not Vested at December 31, 2015** | **702,623** | **$ 53.90** | |

At December 31, 2015, the remaining unrecognized compensation cost from unvested stock-settled performance share awards was $9 million, which includes $2 million related to unvested stock-settled performance share awards tied to Phillips 66 stock held by ConocoPhillips employees, which will be recognized over a weighted-average period of 1.76 years, the longest period being 4.99 years. The weighted-average grant date fair value of stock-settled PSUs granted during 2014 and 2013 was $65.46 and $60.00, respectively. The total fair value of stock-settled PSUs issued during both 2014 and 2013 was $18 million.

*Cash-Settled*
In connection with and immediately following the separation of our Downstream businesses in 2012, grants of new PSUs, subject to a shortened performance period, were authorized. Once granted, these PSUs vest, absent employee election to defer, on the earlier of five years after the grant date of the award or the date the employee becomes eligible for retirement. For employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Otherwise, we recognize compensation expense beginning on the grant date and ending on the date the PSUs are scheduled to vest. These PSUs are settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and thus are classified as liabilities on the balance sheet. Until settlement occurs, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to compensation expense.

Beginning in 2013, PSUs authorized for future grants will vest upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending on the conclusion of the performance period. These PSUs will be settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and are classified as liabilities on the balance sheet.

The following summarizes our cash-settled Performance Share Program activity for the year ended December 31, 2015:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2014 | 675,587 | $ 69.23 | |
| Granted | **903,398** | **46.54** | |
| Settled | **(119,749)** | | **$ 6** |
| **Outstanding at December 31, 2015** | **1,459,236** | **$ 46.54** | |
| **Not Vested at December 31, 2015** | **873,853** | **$ 46.54** | |

At December 31, 2015, the remaining unrecognized compensation cost from unvested cash-settled performance share awards was $18 million, which will be recognized over a weighted-average period of 2.10 years, the longest period being 4.13 years. The weighted-average grant date fair value of cash-settled PSUs granted during 2014 and 2013 was $69.23 and $58.08, respectively. The total fair value of cash-settled performance share awards settled during 2014 and 2013 was zero.

From inception of the Performance Share Program through 2013, approved PSU awards were granted after the conclusion of performance periods. Beginning in February 2014, initial target PSU awards are issued near the beginning of new performance periods. These initial target PSU awards will terminate at the end of the performance periods and will be settled after the performance periods have ended. Also in 2014, initial target PSU awards were issued for open performance periods that began in prior years. For the open performance period beginning in 2012, the initial target PSU awards will terminate at the end of the three-year performance period and will be replaced with approved PSU awards. For the open performance period beginning in 2013, the initial target PSU awards will terminate at the end of the three-year performance period and will be settled after the performance period has ended. There is no effect on recognition of compensation expense.

**Other**—In addition to the above active programs, we have outstanding shares of restricted stock and restricted stock units that were either issued to replace awards held by employees of companies we acquired or issued as part of a compensation program that has been discontinued. Generally, the recipients of the restricted shares or units receive a quarterly dividend or dividend equivalent.

The following summarizes the aggregate activity of these restricted shares and units for the year ended December 31, 2015:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2014 | 1,207,035 | $ 31.48 | |
| Granted | **108,306** | **58.66** | |
| Cancelled | **(6,969)** | **22.62** | |
| Issued | **(36,236)** | | **$ 3** |
| **Outstanding at December 31, 2015** | **1,272,136** | **$ 33.25** | |
| **Not Vested at December 31, 2015** | **-** | | |

At December 31, 2015, all outstanding restricted stock and restricted stock units were fully vested and there was no remaining compensation cost to be recorded. The weighted-average grant date fair value of awards granted during 2014 and 2013 was $71.23 and $62.52, respectively. The total fair value of awards issued during 2014 and 2013 was $3 million and $2 million, respectively.

**Note 19—Income Taxes**

Income taxes charged to income (loss) from continuing operations were:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| **Income Taxes** | | | | |
| Federal | | | | |
| Current | $ | **(718)** | 188 | 724 |
| Deferred | | **(1,443)** | 365 | 811 |
| Foreign | | | | |
| Current | | **745** | 2,846 | 4,249 |
| Deferred | | **(1,315)** | 252 | 504 |
| State and local | | | | |
| Current | | **8** | 46 | 220 |
| Deferred | | **(145)** | (114) | (99) |
| | $ | **(2,868)** | 3,583 | 6,409 |

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Major components of deferred tax liabilities and assets at December 31 were:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2015** | 2014 |
| **Deferred Tax Liabilities** | | | |
| PP&E and intangibles | $ | **16,378** | 20,054 |
| Investment in joint ventures | | **866** | 1,013 |
| Inventory | | **25** | 51 |
| Deferred state income tax | | **128** | 63 |
| Partnership income deferral | | **44** | 155 |
| Other | | **453** | 509 |
| Total deferred tax liabilities | | **17,894** | 21,845 |
| **Deferred Tax Assets** | | | |
| Benefit plan accruals | | **1,160** | 1,552 |
| Asset retirement obligations and accrued environmental costs | | **4,426** | 4,971 |
| Deferred state income tax | | **-** | - |
| Other financial accruals and deferrals | | **616** | 552 |
| Loss and credit carryforwards | | **1,579** | 1,568 |
| Other | | **134** | 329 |
| Total deferred tax assets | | **7,915** | 8,972 |
| Less: valuation allowance | | **(734)** | (970) |
| Net deferred tax assets | | **7,181** | 8,002 |
| Net deferred tax liabilities | $ | **10,713** | 13,843 |

Effective December 31, 2015, we early adopted, on a prospective basis, FASB ASU No. 2015-17, "Balance Sheet Classification of Deferred Taxes." This ASU requires all deferred tax assets and liabilities to be reported as noncurrent. Noncurrent assets and liabilities include deferred taxes of $286 million and $10,999 million, respectively, at December 31, 2015. Current assets, noncurrent assets, current liabilities and noncurrent liabilities included deferred taxes of $865 million, $370 million, $8 million and $15,070 million, respectively, at December 31, 2014. The adoption of this ASU was not reflected on our consolidated statement of cash flows.

We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2016 and 2036 with some carryovers having indefinite carryforward periods.

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2015, valuation allowances decreased a total of $236 million. This decrease primarily relates to the relinquishment of certain assets. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects remaining net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as offsets to the tax consequences of future taxable income.

At December 31, 2015, unremitted income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $3,300 million. Deferred income taxes have not been provided on this amount, as we do not plan to initiate any action that would require the payment of income taxes. Due to the nature of our structures within the jurisdictions in which we operate, as well as the complex nature of the relevant tax laws, it is not practicable to estimate the amount of additional tax, if any, that might be payable on this income if distributed.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2015, 2014 and 2013:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2015** | 2014 | 2013 |
| Balance at January 1 | $ **442** | 655 | 872 |
| Additions based on tax positions related to the current year | **54** | 46 | 52 |
| Additions for tax positions of prior years | **4** | 7 | 30 |
| Reductions for tax positions of prior years | **(37)** | (228) | (251) |
| Settlements | **(4)** | (28) | (48) |
| Lapse of statute | **-** | (10) | - |
| Balance at December 31 | $ **459** | 442 | 655 |

Included in the balance of unrecognized tax benefits for 2015, 2014 and 2013 were $354 million, $348 million and $440 million, respectively, which, if recognized, would impact our effective tax rate.

At December 31, 2015, 2014 and 2013, accrued liabilities for interest and penalties totaled $79 million, $65 million and $120 million, respectively, net of accrued income taxes. Interest and penalties resulted in a reduction to earnings of $11 million in 2015, and a benefit to earnings of $43 million and $9 million in 2014 and 2013, respectively.

We and our subsidiaries file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions are generally complete as follows: United Kingdom (2012), Canada (2009), United States (2010) and Norway (2014). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world. As a consequence, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

The amounts of U.S. and foreign income (loss) from continuing operations before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes, were:

| | Millions of Dollars | | | Percent of Pre-Tax Income (Loss) | | |
|---|---|---|---|---|---|---|
| | **2015** | 2014 | 2013 | **2015** | 2014 | 2013 |
| Income (loss) before income taxes from continuing operations | | | | | | |
| United States | $ **(4,150)** | 2,310 | 5,046 | **57.3 %** | 24.6 | 34.9 |
| Foreign | **(3,089)** | 7,080 | 9,400 | **42.7** | 75.4 | 65.1 |
| | $ **(7,239)** | 9,390 | 14,446 | **100.0 %** | 100.0 | 100.0 |
| Federal statutory income tax | $ **(2,534)** | 3,287 | 5,056 | **35.0 %** | 35.0 | 35.0 |
| Foreign taxes in excess of federal statutory rate | **381** | 376 | 1,389 | **(5.3)** | 4.0 | 9.6 |
| Foreign tax law change | **(426)** | - | - | **5.9** | - | - |
| U.S. fair value election | **(185)** | - | - | **2.6** | - | - |
| Capital loss benefit | **-** | - | (79) | **-** | - | (0.5) |
| Federal manufacturing deduction | **-** | (15) | (35) | **-** | (0.2) | (0.2) |
| State income tax | **(89)** | (44) | 79 | **1.2** | (0.5) | 0.5 |
| Other | **(15)** | (21) | (1) | **0.2** | (0.2) | - |
| | $ **(2,868)** | 3,583 | 6,409 | **39.6 %** | 38.1 | 44.4 |

The increase in the effective tax rate for 2015 was primarily due to the U.K. tax law change and electing the fair market value method of apportioning interest expense for prior years, discussed below; partially offset by lower income in high tax jurisdictions and the Canadian tax law change, discussed below.

The change in the effective tax rate from 2013 to 2014, was primarily due to lower income in high tax jurisdictions.

In the United Kingdom, legislation was enacted on March 26, 2015, to decrease the overall U.K. upstream corporation tax rate from 62 percent to 50 percent effective January 1, 2015. As a result, a $555 million net tax benefit for revaluing the U.K. deferred tax liability is reflected in the “Provision (benefit) for income taxes” line on our consolidated income statement.

In Canada, legislation was enacted on June 29, 2015, to increase the overall Canadian corporation tax rate from 25 percent to 27 percent effective July 1, 2015. As a result, a $129 million net tax expense for revaluing the Canadian deferred tax liability is reflected in the “Provision (benefit) for income taxes” line on our consolidated income statement.

In December 2015, we filed refund claims for prior years electing the fair market value method of apportioning interest in the United States. As a result, a $185 million tax benefit was recorded in the fourth quarter of 2015.

Certain operating losses in jurisdictions outside of the U.S. only yield a tax benefit in the U.S. as a worthless security deduction. For 2015, 2014 and 2013 the amount of the benefit was $491 million, $122 million and $19 million, respectively.

**Note 20—Accumulated Other Comprehensive Income**

Accumulated other comprehensive income (loss) in the equity section of the balance sheet included:

| | Millions of Dollars | | |
|---|---|---|---|
| | Defined Benefit Plans | Foreign Currency Translation | Accumulated Other Comprehensive Income (Loss) |
| December 31, 2012 | $ (1,425) | 5,512 | 4,087 |
| Other comprehensive income (loss) | 601 | (2,686) | (2,085) |
| December 31, 2013 | (824) | 2,826 | 2,002 |
| Other comprehensive loss | (437) | (3,467) | (3,904) |
| December 31, 2014 | (1,261) | (641) | (1,902) |
| Other comprehensive income (loss) | **818** | **(5,163)** | **(4,345)** |
| **December 31, 2015** | **$ (443)** | **(5,804)** | **(6,247)** |

The following table summarizes reclassifications out of accumulated other comprehensive loss during the years ended December 31:

| | Millions of Dollars | |
|---|---|---|
| | **2015** | 2014 |
| Defined Benefit Plans | **$ 251** | 81 |
| *Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:* | *$ 133* | *44* |

*See Note 18—Employee Benefit Plans, for additional information.*

There were no items within accumulated other comprehensive income (loss) related to noncontrolling interests.

**Note 21—Cash Flow Information**

Amounts included in continuing operations for the years ended December 31 were:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2015** | 2014 | 2013 |
| **Noncash Investing and Financing Activities** | | | |
| Increase in PP&E related to an increase in asset retirement obligations* | $ **402** | 1,611 | 1,329 |
| Increase (decrease) in PP&E and debt related to a capital lease asset and obligation | **7** | (84) | 906 |
| **Cash Payments** | | | |
| Interest | $ **920** | 669 | 566 |
| Income taxes** | **523** | 4,203 | 4,910 |
| **Net Sales (Purchases) of Short-Term Investments** | | | |
| Short-term investments purchased | $ **-** | (876) | (361) |
| Short-term investments sold | **-** | 1,129 | 98 |
| | $ **-** | 253 | (263) |

**Includes $68 million and $212 million in 2014 and 2013, respectively, primarily related to the impact of U.K. tax law changes on the deductibility of decommissioning costs.*

***Net of $642 million in 2015 related to a refund received from the Internal Revenue Service for 2014 overpaid taxes.*

In relation to certain working capital changes associated with investing activities, we reclassified $180 million and $55 million of the "Increase (decrease) in accounts payable" line within "Cash Flows From Operating Activities" to the "Working capital changes associated with investing activities" line within "Cash Flows From Investing Activities" for December 31, 2014 and December 31, 2013, respectively. There was no impact to "Cash and Cash Equivalents at End of Period."

**Note 22—Other Financial Information**

Amounts included in continuing operations for the years ended December 31 were:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| **Interest and Debt Expense** | | | | |
| Incurred | | | | |
| Debt | $ | **1,130** | 1,063 | 1,087 |
| Other | | **84** | 73 | 192 |
| | | **1,214** | 1,136 | 1,279 |
| Capitalized | | **(294)** | (488) | (667) |
| Expensed | $ | **920** | 648 | 612 |
| **Other Income** | | | | |
| Interest income | $ | **45** | 83 | 113 |
| Other, net | | **80** | 283 | 261 |
| | $ | **125** | 366 | 374 |
| **Research and Development Expenditures**—expensed | $ | **222** | 263 | 258 |
| **Shipping and Handling Costs*** | $ | **1,181** | 1,360 | 1,137 |

**Amounts included in production and operating expenses.*

| | | | | |
|---|---|---|---|---|
| **Foreign Currency Transaction (Gains) Losses**—after-tax | | | | |
| Alaska | $ | **-** | - | - |
| Lower 48 | | **-** | - | - |
| Canada | | **-** | (4) | (6) |
| Europe and North Africa* | | **(22)** | (56) | (29) |
| Asia Pacific and Middle East | | **(78)** | - | (29) |
| Other International* | | **(9)** | - | - |
| Corporate and Other | | **45** | 16 | 31 |
| | $ | **(64)** | (44) | (33) |

**2014 and 2013 restated to conform to current period presentation.*

| | Millions of Dollars | |
|---|---|---|
| | **2015** | 2014 |
| **Properties, Plants and Equipment** | | |
| Proved properties | **$ 122,796** | 130,448 |
| Unproved properties | **7,410** | 8,951 |
| Other | **6,653** | 6,831 |
| Gross properties, plants and equipment | **136,859** | 146,230 |
| Less: Accumulated depreciation, depletion and amortization | **(70,413)** | (70,786) |
| Net properties, plants and equipment | **$ 66,446** | 75,444 |

## Note 23—Related Party Transactions

Our related parties primarily include equity method investments and certain trusts for the benefit of employees.

Significant transactions with our equity affiliates were:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| Operating revenues and other income | $ | **118** | 119 | 102 |
| Purchases | | **97** | 190 | 184 |
| Operating expenses and selling, general and administrative expenses | | **62** | 70 | 35 |
| Net interest (income) expense* | | **(9)** | (44) | 31 |

**We paid interest to, or received interest from, various affiliates. See Note 7—Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.*

The table above includes transactions with Freeport LNG through the date of the termination agreement and excludes the termination fee. See Note 7—Investments, Loans and Long-Term Receivables, for additional information.

## Note 24—Segment Disclosures and Related Information

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International.

After agreeing to sell our Nigeria business in 2012, we completed the sale in the third quarter of 2014. Results for these operations have been reported as discontinued operations in all periods presented. For additional information, see Note 3—Discontinued Operations.

Effective November 1, 2015, the Other International and historically presented Europe segments were restructured to align with changes to our internal organization structure. The Libya business was moved from the Other International segment to the historically presented Europe segment, which is now renamed Europe and North Africa. Accordingly, results of operations for the Other International and Europe and North Africa segments have been revised in all periods presented. There was no impact on our consolidated financial statements, and the impact on our segment presentation is immaterial.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, corporate overhead and certain technology activities, including licensing revenues. Corporate assets include all cash and cash equivalents.

We evaluate performance and allocate resources based on net income (loss) attributable to ConocoPhillips. Segment accounting policies are the same as those in Note 1—Accounting Policies. Intersegment sales are at prices that approximate market.

**Analysis of Results by Operating Segment**

| | Millions of Dollars | | |
|---|---|---|---|
| | **2015** | 2014 | 2013 |
| **Sales and Other Operating Revenues** | | | |
| Alaska | $ **4,351** | 8,382 | 8,553 |
| Lower 48 | **11,976** | 21,721 | 19,480 |
| Intersegment eliminations | **(63)** | (107) | (104) |
| Lower 48 | **11,913** | 21,614 | 19,376 |
| Canada | **2,454** | 5,162 | 5,254 |
| Intersegment eliminations | **(318)** | (753) | (607) |
| Canada | **2,136** | 4,409 | 4,647 |
| Europe and North Africa | **6,110** | 10,665 | 13,248 |
| Intersegment eliminations | **(4)** | (49) | - |
| Europe and North Africa | **6,106** | 10,616 | 13,248 |
| Asia Pacific and Middle East | **4,746** | 7,425 | 8,426 |
| Intersegment eliminations | **(1)** | (1) | - |
| Asia Pacific and Middle East | **4,745** | 7,424 | 8,426 |
| Other International | **1** | - | - |
| Corporate and Other | **312** | 79 | 163 |
| Consolidated sales and other operating revenues | $ **29,564** | 52,524 | 54,413 |
| | | | |
| **Depreciation, Depletion, Amortization and Impairments** | | | |
| Alaska | $ **690** | 584 | 533 |
| Lower 48 | **4,227** | 3,911 | 3,247 |
| Canada | **788** | 962 | 1,531 |
| Europe and North Africa | **2,565** | 2,345 | 1,363 |
| Asia Pacific and Middle East | **2,981** | 1,275 | 1,188 |
| Other International | **-** | 1 | 1 |
| Corporate and Other | **107** | 107 | 100 |
| Consolidated depreciation, depletion, amortization and impairments | $ **11,358** | 9,185 | 7,963 |

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| **Equity in Earnings of Affiliates** | | | | |
| Alaska | $ | **4** | 9 | 7 |
| Lower 48 | | **(5)** | 1 | (2) |
| Canada | | **78** | 1,385 | 984 |
| Europe and North Africa | | **23** | 37 | 27 |
| Asia Pacific and Middle East | | **550** | 1,089 | 1,162 |
| Other International | | **8** | 9 | 43 |
| Corporate and Other | | **(3)** | (1) | (2) |
| Consolidated equity in earnings of affiliates | $ | **655** | 2,529 | 2,219 |
| | | | | |
| **Income Taxes** | | | | |
| Alaska | $ | **(71)** | 1,081 | 1,275 |
| Lower 48 | | **(1,119)** | (92) | 398 |
| Canada | | **(223)** | 236 | (44) |
| Europe and North Africa | | **(854)** | 1,590 | 3,258 |
| Asia Pacific and Middle East | | **467** | 1,194 | 1,512 |
| Other International | | **(456)** | (102) | 134 |
| Corporate and Other | | **(612)** | (324) | (124) |
| Consolidated income taxes | $ | **(2,868)** | 3,583 | 6,409 |
| | | | | |
| **Net Income (Loss) Attributable to ConocoPhillips** | | | | |
| Alaska | $ | **4** | 2,041 | 2,274 |
| Lower 48 | | **(1,932)** | (22) | 754 |
| Canada | | **(1,044)** | 940 | 718 |
| Europe and North Africa | | **409** | 814 | 1,297 |
| Asia Pacific and Middle East | | **(463)** | 2,939 | 3,532 |
| Other International | | **(593)** | (100) | 223 |
| Corporate and Other | | **(809)** | (874) | (820) |
| Discontinued operations | | **-** | 1,131 | 1,178 |
| Consolidated net income (loss) attributable to ConocoPhillips | $ | **(4,428)** | 6,869 | 9,156 |
| | | | | |
| **Investments In and Advances To Affiliates** | | | | |
| Alaska | $ | **61** | 53 | 53 |
| Lower 48 | | **455** | 471 | 905 |
| Canada | | **8,165** | 9,484 | 10,273 |
| Europe and North Africa | | **70** | 126 | 143 |
| Asia Pacific and Middle East | | **11,780** | 14,022 | 12,806 |
| Other International | | **-** | 59 | 141 |
| Corporate and Other | | **15** | 15 | 16 |
| Consolidated investments in and advances to affiliates | $ | **20,546** | 24,230 | 24,337 |

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2015** | 2014 | 2013 |
| **Total Assets** | | | | |
| Alaska | $ | **12,555** | 12,655 | 11,662 |
| Lower 48 | | **26,932** | 30,185 | 29,552 |
| Canada | | **17,221** | 21,764 | 22,394 |
| Europe and North Africa | | **13,703** | 16,970 | 18,109 |
| Asia Pacific and Middle East | | **22,318** | 25,976 | 25,473 |
| Other International | | **282** | 1,116 | 819 |
| Corporate and Other | | **4,473** | 7,815 | 8,367 |
| Discontinued operations | | **-** | 58 | 1,681 |
| Consolidated total assets | $ | **97,484** | 116,539 | 118,057 |
| | | | | |
| **Capital Expenditures and Investments** | | | | |
| Alaska | $ | **1,352** | 1,564 | 1,140 |
| Lower 48 | | **3,765** | 6,054 | 5,210 |
| Canada | | **1,255** | 2,340 | 2,232 |
| Europe and North Africa | | **1,573** | 2,540 | 3,126 |
| Asia Pacific and Middle East | | **1,812** | 3,877 | 3,382 |
| Other International | | **173** | 520 | 265 |
| Corporate and Other | | **120** | 190 | 182 |
| Consolidated capital expenditures and investments | $ | **10,050** | 17,085 | 15,537 |
| | | | | |
| **Interest Income and Expense** | | | | |
| Interest income | | | | |
| Corporate | $ | **36** | 40 | 60 |
| Lower 48 | | **-** | 35 | 43 |
| Europe and North Africa | | **2** | 2 | 1 |
| Asia Pacific and Middle East | | **6** | 6 | 8 |
| Other International | | **1** | - | 1 |
| Interest and debt expense | | | | |
| Corporate | $ | **920** | 648 | 532 |
| Canada | | **-** | - | 80 |
| | | | | |
| **Sales and Other Operating Revenues by Product** | | | | |
| Crude oil | $ | **12,830** | 23,784 | 24,899 |
| Natural gas | | **11,888** | 20,717 | 22,539 |
| Natural gas liquids | | **952** | 2,245 | 2,111 |
| Other* | | **3,894** | 5,778 | 4,864 |
| Consolidated sales and other operating revenues by product | $ | **29,564** | 52,524 | 54,413 |

**Includes LNG and bitumen.*

**Geographic Information**

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Sales and Other Operating Revenues[1] | | | Long-Lived Assets[2] | | |
| | **2015** | 2014 | 2013 | **2015** | 2014 | 2013 |
| United States | $ **16,284** | 30,019 | 27,954 | **37,445** | 39,641 | 37,593 |
| Australia[3] | **2,127** | 3,258 | 3,571 | **12,788** | 14,969 | 13,450 |
| Canada | **2,136** | 4,409 | 4,647 | **16,766** | 20,874 | 21,380 |
| China | **782** | 1,701 | 2,120 | **1,647** | 1,913 | 2,143 |
| Indonesia | **1,165** | 1,963 | 2,083 | **1,191** | 1,526 | 1,780 |
| Malaysia | **598** | 403 | 281 | **3,599** | 3,811 | 3,406 |
| Norway | **2,107** | 3,794 | 4,323 | **6,933** | 8,142 | 8,089 |
| United Kingdom | **4,005** | 6,594 | 7,717 | **4,154** | 5,327 | 5,959 |
| Other foreign countries | **360** | 383 | 1,717 | **2,469** | 3,471 | 3,364 |
| Worldwide consolidated | $ **29,564** | 52,524 | 54,413 | **86,992** | 99,674 | 97,164 |

*(1)Sales and other operating revenues are attributable to countries based on the location of the operations generating the revenues.*
*(2)Defined as net PP&E plus investments in and advances to affiliated companies.*
*(3)Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.*

**Note 25—New Accounting Standards**

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers" (ASU No. 2014-09), which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers. This ASU supersedes the revenue recognition requirements in FASB ASC Topic 605, "Revenue Recognition," and most industry-specific guidance. This ASU sets forth a five-step model for determining when and how revenue is recognized. Under the model, an entity will be required to recognize revenue to depict the transfer of goods or services to a customer at an amount reflecting the consideration it expects to receive in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts.

In August 2015, the FASB issued ASU No. 2015-14, "Deferral of the Effective Date," which defers the effective date of ASU No. 2014-09. The ASU is now effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for interim and annual periods beginning after December 15, 2016. Entities may choose to adopt the standard using either a full retrospective approach or a modified retrospective approach. We are currently evaluating the impact of the adoption of ASU No. 2014-09 and continue to monitor proposals issued by the FASB to clarify the ASU.

In February 2015, the FASB issued ASU No. 2015-02, "Amendments to the Consolidation Analysis," which amends existing requirements applicable to reporting entities that are required to evaluate whether certain legal entities should be consolidated. The ASU is effective for interim and annual periods beginning after December 15, 2015. Early adoption is permitted. Entities may choose to adopt the standard using either a full retrospective approach or a modified retrospective approach. We do not expect the adoption of this ASU to have a material impact on our consolidated financial statements and disclosures.

**Oil and Gas Operations** (Unaudited)

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, "Extractive Activities—Oil and Gas," and regulations of the U.S. Securities and Exchange Commission (SEC), we are making certain supplemental disclosures about our oil and gas exploration and production operations.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates' oil and gas activities in our operating segments. As a result, amounts reported as equity affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report.

As required by current authoritative guidelines, the estimated future date when an asset will be permanently shut down for economic reasons is based on historical 12-month first-of-month average prices and current costs. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Generally, our proved reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to production sharing contracts (PSCs), which are reported under the "economic interest" method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices, recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. At December 31, 2015, approximately 6 percent of our total proved reserves were under PSCs, located in our Asia Pacific/Middle East geographic reporting area, and 32 percent of our total proved reserves were under a variable-royalty regime, located in our Canada geographic reporting area.

Our reserves disclosures by geographic area include the United States, Canada, Europe (Norway and the United Kingdom), Asia Pacific/Middle East, Africa and Other Areas. Other Areas primarily consists of the Russia and Caspian regions, which we exited in 2015.

As part of our asset disposition program, we sold our interest in Kashagan, and the Algeria and Nigeria businesses. These businesses were considered held for sale since the fourth quarter of 2012 and have been reported as discontinued operations for all periods presented. Accordingly, the Results of Operations, Average Sales Prices and Net Production tables included within the supplemental oil and gas disclosures reflect the associated earnings and production as discontinued operations.

Kashagan and Algeria were both sold in the fourth quarter of 2013. In July 2014, we sold our Nigeria business. See Note 3—Discontinued Operations, for additional information.

**Reserves Governance**

The recording and reporting of proved reserves are governed by criteria established by regulations of the SEC and FASB. Proved reserves are 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain it will commence the project within a reasonable time.

Proved reserves are further classified as either developed or undeveloped. Proved developed reserves are proved reserves that 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, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved reserves expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

We have a companywide, comprehensive, SEC-compliant internal policy that governs the determination and reporting of proved reserves. This policy is applied by the geologists and reservoir engineers in our business units around the world. As part of our internal control process, each business unit's reserve processes and controls are reviewed annually by an internal team which is headed by the company's Manager of Reserves Compliance and Reporting. This team, composed of internal reservoir engineers, geologists, finance personnel and a senior representative from DeGolyer and MacNaughton (D&M), a third-party petroleum engineering consulting firm, reviews the business units' reserves for adherence to SEC guidelines and company policy through on-site visits, teleconferences and review of documentation. In addition to providing independent reviews, this internal team also ensures reserves are calculated using consistent and appropriate standards and procedures. This team is independent of business unit line management and is responsible for reporting its findings to senior management. The team is responsible for communicating our reserves policy and procedures and is available for internal peer reviews and consultation on major projects or technical issues throughout the year. All of our proved reserves held by consolidated companies and our share of equity affiliates have been estimated by ConocoPhillips.

During 2015, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2015, were reviewed by D&M. The purpose of their review was to assess whether the adequacy and effectiveness of our internal processes and controls used to determine estimates of proved reserves are in accordance with SEC regulations. In such review, ConocoPhillips' technical staff presented D&M with an overview of the reserves data, as well as the methods and assumptions used in estimating reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures and relevant economic criteria. Management's intent in retaining D&M to review its processes and controls was to provide objective third-party input on these processes and controls. D&M's opinion was the general processes and controls employed by ConocoPhillips in estimating its December 31, 2015, proved reserves for the properties reviewed are in accordance with the SEC reserves definitions. D&M's report is included as Exhibit 99 of this Annual Report on Form 10-K.

The technical person primarily responsible for overseeing the processes and internal controls used in the preparation of the company's reserve estimates is the Manager of Reserves Compliance and Reporting. This individual holds a master's degree in petroleum engineering. He is a member of the Society of Petroleum Engineers with over 25 years of oil and gas industry experience and has held positions of increasing responsibility in reservoir engineering, subsurface and asset management in the United States and several international field locations.

Engineering estimates of the quantities of proved reserves are inherently imprecise. See the "Critical Accounting Estimates" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional discussion of the sensitivities surrounding these estimates.

## Proved Reserves

| Years Ended December 31 | Crude Oil | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed and Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2012 | 1,148 | 447 | 1,595 | 24 | 487 | 241 | 229 | 108 | 2,684 |
| Revisions | (7) | 20 | 13 | 1 | (5) | 11 | 23 | - | 43 |
| Improved recovery | 20 | - | 20 | 1 | - | - | - | - | 21 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 9 | 235 | 244 | 1 | 19 | 9 | 22 | - | 295 |
| Production | (64) | (56) | (120) | (5) | (42) | (29) | (16) | - | (212) |
| Sales | - | (40) | (40) | - | (3) | - | (21) | (108) | (172) |
| End of 2013 | 1,106 | 606 | 1,712 | 22 | 456 | 232 | 237 | - | 2,659 |
| Revisions | (6) | 25 | 19 | 3 | (1) | 5 | - | - | 26 |
| Improved recovery | 8 | - | 8 | 2 | - | 3 | - | - | 13 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 16 | 116 | 132 | 2 | - | 16 | - | - | 150 |
| Production | (61) | (71) | (132) | (5) | (44) | (29) | (5) | - | (215) |
| Sales | - | - | - | - | - | - | (28) | - | (28) |
| End of 2014 | 1,063 | 676 | 1,739 | 24 | 411 | 227 | 204 | - | 2,605 |
| Revisions | (115) | (69) | (184) | - | (21) | (29) | - | - | (234) |
| Improved recovery | 4 | 4 | 8 | 1 | - | 31 | - | - | 40 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 20 | 57 | 77 | 1 | - | 7 | - | - | 85 |
| Production | (57) | (78) | (135) | (4) | (44) | (33) | - | - | (216) |
| Sales | - | (2) | (2) | (8) | - | - | - | - | (10) |
| **End of 2015** | 915 | 588 | 1,503 | 14 | 346 | 203 | 204 | - | 2,270 |
| *Equity affiliates* | | | | | | | | | |
| End of 2012 | - | - | - | - | - | 91 | - | 4 | 95 |
| Revisions | - | - | - | - | - | - | - | 1 | 1 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (5) | - | (1) | (6) |
| Sales | - | - | - | - | - | - | - | - | - |
| End of 2013 | - | - | - | - | - | 86 | - | 4 | 90 |
| Revisions | - | - | - | - | - | 17 | - | 3 | 20 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (5) | - | (2) | (7) |
| Sales | - | - | - | - | - | - | - | - | - |
| End of 2014 | - | - | - | - | - | 98 | - | 5 | 103 |
| Revisions | - | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (5) | - | (1) | (6) |
| Sales | - | - | - | - | - | - | - | (4) | (4) |
| **End of 2015** | - | - | - | - | - | 93 | - | - | 93 |
| *Total company* | | | | | | | | | |
| End of 2012 | 1,148 | 447 | 1,595 | 24 | 487 | 332 | 229 | 112 | 2,779 |
| End of 2013 | 1,106 | 606 | 1,712 | 22 | 456 | 318 | 237 | 4 | 2,749 |
| End of 2014 | 1,063 | 676 | 1,739 | 24 | 411 | 325 | 204 | 5 | 2,708 |
| **End of 2015** | 915 | 588 | 1,503 | 14 | 346 | 296 | 204 | - | 2,363 |

| Years Ended December 31 | Crude Oil | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2012 | 1,017 | 271 | 1,288 | 23 | 267 | 136 | 217 | - | 1,931 |
| End of 2013 | 1,003 | 268 | 1,271 | 22 | 247 | 126 | 230 | - | 1,896 |
| End of 2014 | 950 | 313 | 1,263 | 23 | 237 | 142 | 199 | - | 1,864 |
| **End of 2015** | 819 | 283 | 1,102 | 13 | 200 | 139 | 204 | - | 1,658 |
| *Equity affiliates* | | | | | | | | | |
| End of 2012 | - | - | - | - | - | 91 | - | 4 | 95 |
| End of 2013 | - | - | - | - | - | 86 | - | 4 | 90 |
| End of 2014 | - | - | - | - | - | 98 | - | 5 | 103 |
| **End of 2015** | - | - | - | - | - | 93 | - | - | 93 |
| **Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2012 | 131 | 176 | 307 | 1 | 220 | 105 | 12 | 108 | 753 |
| End of 2013 | 103 | 338 | 441 | - | 209 | 106 | 7 | - | 763 |
| End of 2014 | 113 | 363 | 476 | 1 | 174 | 85 | 5 | - | 741 |
| **End of 2015** | 96 | 305 | 401 | 1 | 146 | 64 | - | - | 612 |
| *Equity affiliates* | | | | | | | | | |
| End of 2012 | - | - | - | - | - | - | - | - | - |
| End of 2013 | - | - | - | - | - | - | - | - | - |
| End of 2014 | - | - | - | - | - | - | - | - | - |
| **End of 2015** | - | - | - | - | - | - | - | - | - |

Notable changes in proved crude oil reserves in the three years ended December 31, 2015, included:

- Revisions: In 2015, revisions in Alaska, Lower 48 and Asia Pacific/Middle East were primarily due to lower prices.
- Extensions and discoveries: In 2014 and 2013, extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford and Bakken.
- Sales: In 2014, sales in Africa reflect the sale of the Nigeria business. In 2013, sales in Lower 48 primarily reflect the majority of our producing zones in the Cedar Creek Anticline, sales in Africa reflect the sale of the Algeria business and sales in Other Areas reflect the sale of our interest in Kashagan.

| Years Ended December 31 | Natural Gas Liquids | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed and Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2012 | 122 | 403 | 525 | 52 | 30 | 22 | 17 | - | 646 |
| Revisions | 9 | 36 | 45 | 10 | - | (5) | - | - | 50 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | 58 | 58 | 2 | - | 2 | - | - | 62 |
| Production | (6) | (34) | (40) | (8) | (2) | (5) | (1) | - | (56) |
| Sales | - | (1) | (1) | - | - | - | (2) | - | (3) |
| End of 2013 | 125 | 462 | 587 | 56 | 28 | 14 | 14 | - | 699 |
| Revisions | - | (13) | (13) | 15 | (1) | 2 | - | - | 3 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | 26 | 26 | 3 | - | - | - | - | 29 |
| Production | (5) | (35) | (40) | (8) | (3) | (3) | (1) | - | (55) |
| Sales | - | - | - | (1) | - | - | (13) | - | (14) |
| End of 2014 | 120 | 440 | 560 | 65 | 24 | 13 | - | - | 662 |
| Revisions | (1) | (84) | (85) | (10) | (1) | (2) | - | - | (98) |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | 10 | 10 | 2 | - | - | - | - | 12 |
| Production | (5) | (36) | (41) | (9) | (3) | (3) | - | - | (56) |
| Sales | - | (9) | (9) | (3) | - | - | - | - | (12) |
| **End of 2015** | 114 | 321 | 435 | 45 | 20 | 8 | - | - | 508 |
| *Equity affiliates* | | | | | | | | | |
| End of 2012 | - | - | - | - | - | 48 | - | - | 48 |
| Revisions | - | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (3) | - | - | (3) |
| Sales | - | - | - | - | - | - | - | - | - |
| End of 2013 | - | - | - | - | - | 45 | - | - | 45 |
| Revisions | - | - | - | - | - | 10 | - | - | 10 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (2) | - | - | (2) |
| Sales | - | - | - | - | - | - | - | - | - |
| End of 2014 | - | - | - | - | - | 53 | - | - | 53 |
| Revisions | - | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (3) | - | - | (3) |
| Sales | - | - | - | - | - | - | - | - | - |
| **End of 2015** | - | - | - | - | - | 50 | - | - | 50 |
| *Total company* | | | | | | | | | |
| End of 2012 | 122 | 403 | 525 | 52 | 30 | 70 | 17 | - | 694 |
| End of 2013 | 125 | 462 | 587 | 56 | 28 | 59 | 14 | - | 744 |
| End of 2014 | 120 | 440 | 560 | 65 | 24 | 66 | - | - | 715 |
| **End of 2015** | 114 | 321 | 435 | 45 | 20 | 58 | - | - | 558 |

| Years Ended December 31 | Natural Gas Liquids | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2012 | 121 | 335 | 456 | 49 | 17 | 22 | 15 | - | 559 |
| End of 2013 | 125 | 362 | 487 | 50 | 19 | 13 | 14 | - | 583 |
| End of 2014 | 120 | 337 | 457 | 57 | 18 | 11 | - | - | 543 |
| **End of 2015** | 114 | 235 | 349 | 45 | 16 | 8 | - | - | 418 |
| *Equity affiliates* | | | | | | | | | |
| End of 2012 | - | - | - | - | - | 48 | - | - | 48 |
| End of 2013 | - | - | - | - | - | 45 | - | - | 45 |
| End of 2014 | - | - | - | - | - | 53 | - | - | 53 |
| **End of 2015** | - | - | - | - | - | 50 | - | - | 50 |
| **Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2012 | 1 | 68 | 69 | 3 | 13 | - | 2 | - | 87 |
| End of 2013 | - | 100 | 100 | 6 | 9 | 1 | - | - | 116 |
| End of 2014 | - | 103 | 103 | 8 | 6 | 2 | - | - | 119 |
| **End of 2015** | - | 86 | 86 | - | 4 | - | - | - | 90 |
| *Equity affiliates* | | | | | | | | | |
| End of 2012 | - | - | - | - | - | - | - | - | - |
| End of 2013 | - | - | - | - | - | - | - | - | - |
| End of 2014 | - | - | - | - | - | - | - | - | - |
| **End of 2015** | - | - | - | - | - | - | - | - | - |

Notable changes in proved natural gas liquids reserves in the three years ended December 31, 2015, included:

- *Revisions*: In 2015, revisions in Lower 48 and Canada were primarily due to lower prices. In 2013, revisions in Lower 48 were due to higher prices in 2013 versus 2012, as well as improved well performance.

- *Extensions and discoveries*: In 2014, extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford and Bakken. In 2013, extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford, Barnett and Bakken.

| Years Ended December 31 | Natural Gas | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Billions of Cubic Feet | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed and Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2012 | 2,870 | 6,597 | 9,467 | 1,764 | 1,806 | 2,348 | 913 | 58 | 16,356 |
| Revisions | 73 | 214 | 287 | 344 | 16 | (53) | 94 | - | 688 |
| Improved recovery | 6 | - | 6 | - | - | - | - | - | 6 |
| Purchases | - | - | - | 1 | - | - | - | - | 1 |
| Extensions and discoveries | 2 | 508 | 510 | 55 | 159 | 35 | 6 | - | 765 |
| Production | (86) | (592) | (678) | (283) | (171) | (284) | (63) | - | (1,479) |
| Sales | - | (16) | (16) | (3) | (1) | - | - | (58) | (78) |
| End of 2013 | 2,865 | 6,711 | 9,576 | 1,878 | 1,809 | 2,046 | 950 | - | 16,259 |
| Revisions | (75) | 581 | 506 | 225 | (54) | 115 | - | - | 792 |
| Improved recovery | - | - | - | - | - | 3 | - | - | 3 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 7 | 256 | 263 | 85 | - | 3 | - | - | 351 |
| Production | (78) | (601) | (679) | (259) | (182) | (289) | (34) | - | (1,443) |
| Sales | - | (2) | (2) | (13) | - | - | (689) | - | (704) |
| End of 2014 | 2,719 | 6,945 | 9,664 | 1,916 | 1,573 | 1,878 | 227 | - | 15,258 |
| Revisions | (293) | (884) | (1,177) | (111) | (27) | 110 | - | - | (1,205) |
| Improved recovery | - | - | - | 1 | - | 8 | - | - | 9 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 4 | 103 | 107 | 44 | - | 2 | - | - | 153 |
| Production | (83) | (588) | (671) | (261) | (187) | (285) | - | - | (1,404) |
| Sales | - | (405) | (405) | (482) | - | - | - | - | (887) |
| **End of 2015** | 2,347 | 5,171 | 7,518 | 1,107 | 1,359 | 1,713 | 227 | - | 11,924 |
| *Equity affiliates* | | | | | | | | | |
| End of 2012 | - | - | - | - | - | 3,258 | - | - | 3,258 |
| Revisions | - | - | - | - | - | 65 | - | - | 65 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 982 | - | - | 982 |
| Production | - | - | - | - | - | (176) | - | - | (176) |
| Sales | - | - | - | - | - | - | - | - | - |
| End of 2013 | - | - | - | - | - | 4,129 | - | - | 4,129 |
| Revisions | - | - | - | - | - | 768 | - | - | 768 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 531 | - | - | 531 |
| Production | - | - | - | - | - | (186) | - | - | (186) |
| Sales | - | - | - | - | - | - | - | - | - |
| End of 2014 | - | - | - | - | - | 5,242 | - | - | 5,242 |
| Revisions | - | - | - | - | - | (2) | - | - | (2) |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 268 | - | - | 268 |
| Production | - | - | - | - | - | (239) | - | - | (239) |
| Sales | - | - | - | - | - | - | - | - | - |
| **End of 2015** | - | - | - | - | - | 5,269 | - | - | 5,269 |
| *Total company* | | | | | | | | | |
| End of 2012 | 2,870 | 6,597 | 9,467 | 1,764 | 1,806 | 5,606 | 913 | 58 | 19,614 |
| End of 2013 | 2,865 | 6,711 | 9,576 | 1,878 | 1,809 | 6,175 | 950 | - | 20,388 |
| End of 2014 | 2,719 | 6,945 | 9,664 | 1,916 | 1,573 | 7,120 | 227 | - | 20,500 |
| **End of 2015** | 2,347 | 5,171 | 7,518 | 1,107 | 1,359 | 6,982 | 227 | - | 17,193 |

| Years Ended December 31 | Natural Gas | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Billions of Cubic Feet | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2012 | 2,805 | 5,737 | 8,542 | 1,684 | 1,290 | 1,696 | 846 | - | 14,058 |
| End of 2013 | 2,815 | 5,822 | 8,637 | 1,786 | 1,276 | 1,593 | 881 | - | 14,173 |
| End of 2014 | 2,663 | 5,922 | 8,585 | 1,801 | 1,182 | 1,553 | 226 | - | 13,347 |
| **End of 2015** | 2,313 | 4,458 | 6,771 | 1,101 | 1,088 | 1,421 | 227 | - | 10,608 |
| *Equity affiliates* | | | | | | | | | |
| End of 2012 | - | - | - | - | - | 2,723 | - | - | 2,723 |
| End of 2013 | - | - | - | - | - | 2,606 | - | - | 2,606 |
| End of 2014 | - | - | - | - | - | 3,954 | - | - | 3,954 |
| **End of 2015** | - | - | - | - | - | 4,482 | - | - | 4,482 |
| **Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2012 | 65 | 860 | 925 | 80 | 516 | 652 | 67 | 58 | 2,298 |
| End of 2013 | 50 | 889 | 939 | 92 | 533 | 453 | 69 | - | 2,086 |
| End of 2014 | 56 | 1,023 | 1,079 | 115 | 391 | 325 | 1 | - | 1,911 |
| **End of 2015** | 34 | 713 | 747 | 6 | 271 | 292 | - | - | 1,316 |
| *Equity affiliates* | | | | | | | | | |
| End of 2012 | - | - | - | - | - | 535 | - | - | 535 |
| End of 2013 | - | - | - | - | - | 1,523 | - | - | 1,523 |
| End of 2014 | - | - | - | - | - | 1,288 | - | - | 1,288 |
| **End of 2015** | - | - | - | - | - | 787 | - | - | 787 |

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed in production operations.

Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Notable changes in proved natural gas reserves in the three years ended December 31, 2015, included:

- Revisions: In 2015, revisions in Lower 48, Alaska and Canada were primarily due to lower prices, partially offset by positive revisions in Asia Pacific/Middle East from Indonesia. In 2014, revisions were primarily due to higher prices, increased development activity and strong well performance in Lower 48 and higher prices and improved well performance in Canada and our consolidated operations in Asia Pacific/Middle East. This was partially offset by lower prices and higher costs in Alaska. For our equity affiliates in Asia Pacific/Middle East, 2014 revisions were primarily due to strong field performance. In 2013, revisions were primarily due to higher prices in 2013 versus 2012, and improved well performance in Lower 48 and Canada.

- Extensions and discoveries: In 2014, extensions and discoveries in Lower 48 and Canada were primarily due to continued drilling success in Eagle Ford and Bakken and ongoing development activity in western Canada. In 2013, extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford, Bakken and Barnett. In 2015, 2014 and 2013, for our equity affiliates in Asia Pacific/Middle East, extensions and discoveries were due to APLNG's ongoing development drilling onshore Australia.

- Sales: In 2015, Lower 48 sales were due to the disposition of non-core assets in South Texas, East Texas and North Louisiana and sales of assets in British Columbia, Saskatchewan and Alberta impacted Canada. In 2014, for our consolidated operations in Africa, sales were due to the sale of the Nigeria business.

| Years Ended December 31 | Bitumen Millions of Barrels Canada |
|---|---|
| **Developed and Undeveloped** | |
| *Consolidated operations* | |
| End of 2012 | 506 |
| Revisions | 56 |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 22 |
| Production | (5) |
| Sales | - |
| End of 2013 | 579 |
| Revisions | (8) |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 31 |
| Production | (4) |
| Sales | - |
| End of 2014 | 598 |
| Revisions | 94 |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | - |
| Production | (5) |
| Sales | - |
| **End of 2015** | 687 |
| | |
| *Equity affiliates* | |
| End of 2012 | 1,394 |
| Revisions | 46 |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 46 |
| Production | (35) |
| Sales | - |
| End of 2013 | 1,451 |
| Revisions | (14) |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 74 |
| Production | (43) |
| Sales | - |
| End of 2014 | 1,468 |
| Revisions | 190 |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 99 |
| Production | (51) |
| Sales | - |
| **End of 2015** | 1,706 |
| | |
| *Total company* | |
| End of 2012 | 1,900 |
| End of 2013 | 2,030 |
| End of 2014 | 2,066 |
| **End of 2015** | 2,393 |

| Years Ended December 31 | **Bitumen** |
|---|---|
| | Millions of Barrels |
| | Canada |
| **Developed** | |
| *Consolidated operations* | |
| End of 2012 | 25 |
| End of 2013 | 16 |
| End of 2014 | 13 |
| **End of 2015** | 111 |
| *Equity affiliates* | |
| End of 2012 | 170 |
| End of 2013 | 181 |
| End of 2014 | 187 |
| **End of 2015** | 311 |
| **Undeveloped** | |
| *Consolidated operations* | |
| End of 2012 | 481 |
| End of 2013 | 563 |
| End of 2014 | 585 |
| **End of 2015** | 576 |
| *Equity affiliates* | |
| End of 2012 | 1,224 |
| End of 2013 | 1,270 |
| End of 2014 | 1,281 |
| **End of 2015** | 1,395 |

Notable changes in proved bitumen reserves in the three years ended December 31, 2015, included:

- Revisions: In 2015, for both our consolidated operations and equity affiliates revisions were primarily related to reduced royalties from lower prices at Surmont, Foster Creek, Christina Lake and Narrows Lake. In 2013, for our consolidated operations revisions were primarily related to ongoing project development at Surmont and improved well performance.

- Extensions and discoveries: In 2015, for our equity affiliates extensions and discoveries were related to approval of development at Christina Lake. In 2014, for our consolidated operations extensions and discoveries were primarily related to delineation activity at Surmont. In 2014, for our equity affiliates extensions and discoveries were primarily related to delineation activity at Foster Creek and Christina Lake, as well as regulatory approval of a development area at Foster Creek.

| Years Ended December 31 | Total Proved Reserves | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels of Oil Equivalent | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed and Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2012 | 1,748 | 1,950 | 3,698 | 876 | 818 | 655 | 398 | 117 | 6,562 |
| Revisions | 14 | 92 | 106 | 124 | (3) | (2) | 38 | - | 263 |
| Improved recovery | 21 | - | 21 | 1 | - | - | - | - | 22 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 9 | 378 | 387 | 35 | 46 | 16 | 23 | - | 507 |
| Production | (84) | (189) | (273) | (65) | (73) | (81) | (27) | - | (519) |
| Sales | - | (44) | (44) | (1) | (3) | - | (23) | (117) | (188) |
| End of 2013 | 1,708 | 2,187 | 3,895 | 970 | 785 | 588 | 409 | - | 6,647 |
| Revisions | (19) | 109 | 90 | 48 | (10) | 26 | - | - | 154 |
| Improved recovery | 8 | - | 8 | 2 | - | 3 | - | - | 13 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 17 | 184 | 201 | 50 | - | 17 | - | - | 268 |
| Production | (78) | (206) | (284) | (61) | (78) | (81) | (11) | - | (515) |
| Sales | - | - | - | (3) | - | - | (156) | - | (159) |
| End of 2014 | 1,636 | 2,274 | 3,910 | 1,006 | 697 | 553 | 242 | - | 6,408 |
| Revisions | (165) | (301) | (466) | 66 | (26) | (12) | - | - | (438) |
| Improved recovery | 4 | 4 | 8 | 2 | - | 32 | - | - | 42 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 20 | 84 | 104 | 10 | - | 8 | - | - | 122 |
| Production | (75) | (211) | (286) | (62) | (78) | (84) | - | - | (510) |
| Sales | - | (79) | (79) | (92) | - | - | - | - | (171) |
| **End of 2015** | 1,420 | 1,771 | 3,191 | 930 | 593 | 497 | 242 | - | 5,453 |
| *Equity affiliates* | | | | | | | | | |
| End of 2012 | - | - | - | 1,394 | - | 682 | - | 4 | 2,080 |
| Revisions | - | - | - | 46 | - | 11 | - | 1 | 58 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | 46 | - | 164 | - | - | 210 |
| Production | - | - | - | (35) | - | (38) | - | (1) | (74) |
| Sales | - | - | - | - | - | - | - | - | - |
| End of 2013 | - | - | - | 1,451 | - | 819 | - | 4 | 2,274 |
| Revisions | - | - | - | (14) | - | 155 | - | 3 | 144 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | 74 | - | 89 | - | - | 163 |
| Production | - | - | - | (43) | - | (38) | - | (2) | (83) |
| Sales | - | - | - | - | - | - | - | - | - |
| End of 2014 | - | - | - | 1,468 | - | 1,025 | - | 5 | 2,498 |
| Revisions | - | - | - | 190 | - | (1) | - | - | 189 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | 99 | - | 45 | - | - | 144 |
| Production | - | - | - | (51) | - | (48) | - | (1) | (100) |
| Sales | - | - | - | - | - | - | - | (4) | (4) |
| **End of 2015** | - | - | - | 1,706 | - | 1,021 | - | - | 2,727 |
| *Total company* | | | | | | | | | |
| End of 2012 | 1,748 | 1,950 | 3,698 | 2,270 | 818 | 1,337 | 398 | 121 | 8,642 |
| End of 2013 | 1,708 | 2,187 | 3,895 | 2,421 | 785 | 1,407 | 409 | 4 | 8,921 |
| End of 2014 | 1,636 | 2,274 | 3,910 | 2,474 | 697 | 1,578 | 242 | 5 | 8,906 |
| **End of 2015** | 1,420 | 1,771 | 3,191 | 2,636 | 593 | 1,518 | 242 | - | 8,180 |

| Years Ended December 31 | Total Proved Reserves | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels of Oil Equivalent | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2012 | 1,606 | 1,562 | 3,168 | 377 | 499 | 441 | 373 | - | 4,858 |
| End of 2013 | 1,597 | 1,600 | 3,197 | 386 | 478 | 405 | 391 | - | 4,857 |
| End of 2014 | 1,514 | 1,637 | 3,151 | 393 | 452 | 412 | 237 | - | 4,645 |
| **End of 2015** | 1,318 | 1,261 | 2,579 | 352 | 398 | 384 | 242 | - | 3,955 |
| *Equity affiliates* | | | | | | | | | |
| End of 2012 | - | - | - | 170 | - | 593 | - | 4 | 767 |
| End of 2013 | - | - | - | 181 | - | 565 | - | 4 | 750 |
| End of 2014 | - | - | - | 187 | - | 810 | - | 5 | 1,002 |
| **End of 2015** | - | - | - | 311 | - | 890 | - | - | 1,201 |
| **Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2012 | 142 | 388 | 530 | 499 | 319 | 214 | 25 | 117 | 1,704 |
| End of 2013 | 111 | 587 | 698 | 584 | 307 | 183 | 18 | - | 1,790 |
| End of 2014 | 122 | 637 | 759 | 613 | 245 | 141 | 5 | - | 1,763 |
| **End of 2015** | 102 | 510 | 612 | 578 | 195 | 113 | - | - | 1,498 |
| *Equity affiliates* | | | | | | | | | |
| End of 2012 | - | - | - | 1,224 | - | 89 | - | - | 1,313 |
| End of 2013 | - | - | - | 1,270 | - | 254 | - | - | 1,524 |
| End of 2014 | - | - | - | 1,281 | - | 215 | - | - | 1,496 |
| **End of 2015** | - | - | - | 1,395 | - | 131 | - | - | 1,526 |

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE.

## Proved Undeveloped Reserves

We had 3,024 million BOE of proved undeveloped reserves at year-end 2015, compared with 3,259 million BOE at year-end 2014. During 2015, we converted 595 million BOE of undeveloped reserves to developed, primarily through ongoing development activities, as well as from the startup of major development projects. In addition, we added 360 million BOE of undeveloped reserves in 2015, mainly through extensions and discoveries from ongoing development progress. As a result, at December 31, 2015, our proved undeveloped reserves represented 37 percent of total proved reserves, which was unchanged from December 31, 2014. Costs incurred for the year ended December 31, 2015, relating to the development of proved undeveloped reserves were $6.8 billion. A portion of our costs incurred each year relate to development projects where the proved undeveloped reserves will be converted to proved developed reserves in future years.

Approximately 77 percent of our proved undeveloped reserves at year-end 2015 were associated with five major development areas. Four of the major development areas are currently producing and are expected to have proved undeveloped reserves convert to proved developed over time, as development activities continue and/or production facilities are expanded or upgraded, and include:

- The Surmont oil sands project in Canada.
- FCCL oil sands—Foster Creek and Christina Lake in Canada.
- The Eagle Ford area in the Lower 48.

The remaining major development area, Narrows Lake in our FCCL oil sands in Canada, was sanctioned for development in 2012.

At the end of 2015, approximately 26 percent of our total proved undeveloped reserves, located in the Athabasca oil sands in Canada, have remained undeveloped for five years or more. The oil sands in Canada consist of the FCCL and Surmont steam-assisted gravity drainage (SAGD) projects. The majority of our remaining proved undeveloped reserves in this area were recorded beginning in 2007. Our SAGD projects are large, multi-year projects with steady, long-term production at consistent levels. The associated undeveloped reserves are expected to be developed over the life of the project, as additional well pairs are drilled to maintain throughput at the central processing facilities.

**Results of Operations**

The company's results of operations from oil and gas activities for the years 2015, 2014 and 2013 are shown in the following tables. Non-oil and gas activities, such as pipeline and marine operations, liquefied natural gas operations, crude oil and gas marketing activities, and the profit element of transportation operations in which we have an ownership interest are excluded. Additional information about selected line items within the results of operations tables is shown below:

- Sales include sales to unaffiliated entities attributable primarily to the company's net working interests and royalty interests. Sales are net of fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are not consolidated.

- Transportation costs reflect fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are consolidated.

- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.

- Production costs include costs incurred to operate and maintain wells, related equipment and facilities used in the production of petroleum liquids and natural gas.

- Taxes other than income taxes include production, property and other non-income taxes.

- Depreciation of support equipment is reclassified as applicable.

- Other related expenses include inventory fluctuations, foreign currency transaction gains and losses and other miscellaneous expenses.

## Results of Operations

| Year Ended December 31, 2015 | | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| *Consolidated operations* | | | | | | | | | | |
| Sales | $ | 3,206 | 4,992 | 8,198 | 930 | 3,637 | 2,741 | - | - | 15,506 |
| Transfers | | 15 | - | 15 | - | - | 629 | - | - | 644 |
| Transportation costs | | (599) | - | (599) | - | - | (40) | - | - | (639) |
| Other revenues | | (5) | 452 | 447 | (19) | (28) | 6 | 13 | 2 | 421 |
| Total revenues | | 2,617 | 5,444 | 8,061 | 911 | 3,609 | 3,336 | 13 | 2 | 15,932 |
| Production costs excluding taxes | | 1,242 | 2,420 | 3,662 | 923 | 1,137 | 815 | 42 | 1 | 6,580 |
| Taxes other than income taxes | | 281 | 358 | 639 | 62 | 35 | 33 | 3 | 1 | 773 |
| Exploration expenses | | 682 | 1,583 | 2,265 | 457 | 170 | 268 | 990 | 43 | 4,193 |
| Depreciation, depletion and amortization | | 548 | 4,192 | 4,740 | 777 | 1,813 | 1,321 | - | - | 8,651 |
| Impairments | | 8 | (2) | 6 | 3 | 724 | 3 | - | - | 736 |
| Other related expenses | | (30) | 78 | 48 | 8 | 9 | (2) | (8) | 5 | 60 |
| Accretion | | 52 | 83 | 135 | 49 | 240 | 34 | - | - | 458 |
| | | (166) | (3,268) | (3,434) | (1,368) | (519) | 864 | (1,014) | (48) | (5,519) |
| Provision for income taxes | | (89) | (1,193) | (1,282) | (244) | (816) | 430 | (406) | (27) | (2,345) |
| Results of operations | $ | (77) | (2,075) | (2,152) | (1,124) | 297 | 434 | (608) | (21) | (3,174) |
| | | | | | | | | | | |
| *Equity affiliates* | | | | | | | | | | |
| Sales | $ | - | - | - | 917 | - | 536 | - | 50 | 1,503 |
| Transfers | | - | - | - | - | - | 950 | - | - | 950 |
| Transportation costs | | - | - | - | - | - | - | - | - | - |
| Other revenues | | - | - | - | 34 | - | 4 | - | 58 | 96 |
| Total revenues | | - | - | - | 951 | - | 1,490 | - | 108 | 2,549 |
| Production costs excluding taxes | | - | - | - | 474 | - | 248 | - | 13 | 735 |
| Taxes other than income taxes | | - | - | - | 15 | - | 723 | - | 13 | 751 |
| Exploration expenses | | - | - | - | 12 | - | 190 | - | - | 202 |
| Depreciation, depletion and amortization | | - | - | - | 367 | - | 197 | - | 5 | 569 |
| Impairments | | - | - | - | - | - | 1,396 | - | 3 | 1,399 |
| Other related expenses | | - | - | - | (2) | - | (13) | - | 23 | 8 |
| Accretion | | - | - | - | 7 | - | 10 | - | 1 | 18 |
| | | - | - | - | 78 | - | (1,261) | - | 50 | (1,133) |
| Provision for income taxes | | - | - | - | 20 | - | (155) | - | 10 | (125) |
| Results of operations | $ | - | - | - | 58 | - | (1,106) | - | 40 | (1,008) |

| Year Ended December 31, 2014 | | Millions of Dollars | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Disc Ops | Total |
| *Consolidated operations* | | | | | | | | | | | |
| Sales | $ | 6,202 | 9,098 | 15,300 | 2,091 | 6,160 | 4,550 | 185 | - | 278 | 28,564 |
| Transfers | | 47 | 94 | 141 | - | - | 938 | - | - | - | 1,079 |
| Transportation costs | | (659) | - | (659) | - | - | (43) | - | - | - | (702) |
| Other revenues | | 13 | 29 | 42 | 185 | (25) | 46 | 26 | 154 | 1,052 | 1,480 |
| Total revenues | | 5,603 | 9,221 | 14,824 | 2,276 | 6,135 | 5,491 | 211 | 154 | 1,330 | 30,421 |
| Production costs excluding taxes | | 1,205 | 2,482 | 3,687 | 1,106 | 1,410 | 994 | 83 | 1 | 128 | 7,409 |
| Taxes other than income taxes | | 842 | 700 | 1,542 | 62 | 44 | 299 | 5 | 1 | 8 | 1,961 |
| Exploration expenses | | 46 | 1,042 | 1,088 | 317 | 148 | 123 | 303 | 40 | 4 | 2,023 |
| Depreciation, depletion and amortization | | 423 | 3,662 | 4,085 | 919 | 1,777 | 1,125 | 6 | - | - | 7,912 |
| Impairments | | 56 | 107 | 163 | 38 | 529 | 7 | - | - | - | 737 |
| Other related expenses | | 2 | 96 | 98 | 7 | (233) | (6) | (1) | 9 | (9) | (135) |
| Accretion | | 52 | 80 | 132 | 57 | 245 | 26 | - | - | - | 460 |
| | | 2,977 | 1,052 | 4,029 | (230) | 2,215 | 2,923 | (185) | 103 | 1,199 | 10,054 |
| Provision for income taxes | | 1,043 | 322 | 1,365 | (101) | 1,452 | 1,216 | 4 | (13) | 79 | 4,002 |
| Results of operations | $ | 1,934 | 730 | 2,664 | (129) | 763 | 1,707 | (189) | 116 | 1,120 | 6,052 |
| | | | | | | | | | | | |
| *Equity affiliates* | | | | | | | | | | | |
| Sales | $ | - | - | - | 2,307 | - | 851 | - | 96 | - | 3,254 |
| Transfers | | - | - | - | - | - | 1,663 | - | - | - | 1,663 |
| Transportation costs | | - | - | - | - | - | - | - | - | - | - |
| Other revenues | | - | - | - | 33 | - | 3 | - | - | - | 36 |
| Total revenues | | - | - | - | 2,340 | - | 2,517 | - | 96 | - | 4,953 |
| Production costs excluding taxes | | - | - | - | 651 | - | 221 | - | 18 | - | 890 |
| Taxes other than income taxes | | - | - | - | 14 | - | 1,214 | - | 51 | - | 1,279 |
| Exploration expenses | | - | - | - | 13 | 7 | 8 | - | - | - | 28 |
| Depreciation, depletion and amortization | | - | - | - | 337 | - | 171 | - | 7 | - | 515 |
| Impairments | | - | - | - | - | - | 27 | - | - | - | 27 |
| Other related expenses | | - | - | - | (65) | 1 | (2) | - | 27 | - | (39) |
| Accretion | | - | - | - | 6 | - | 8 | - | 1 | - | 15 |
| | | - | - | - | 1,384 | (8) | 870 | - | (8) | - | 2,238 |
| Provision for income taxes | | - | - | - | 331 | - | (62) | - | 2 | - | 271 |
| Results of operations | $ | - | - | - | 1,053 | (8) | 932 | - | (10) | - | 1,967 |

| Year Ended December 31, 2013 | | Millions of Dollars | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Disc Ops | Total |
| *Consolidated operations* | | | | | | | | | | | |
| Sales | $ | 7,235 | 7,954 | 15,189 | 1,890 | 6,319 | 5,261 | 1,001 | - | 855 | 30,515 |
| Transfers | | 15 | 183 | 198 | - | - | 981 | - | - | - | 1,179 |
| Transportation costs | | (703) | - | (703) | - | - | (39) | - | - | - | (742) |
| Other revenues | | (5) | 57 | 52 | 775 | (21) | 149 | 141 | 29 | 960 | 2,085 |
| Total revenues | | 6,542 | 8,194 | 14,736 | 2,665 | 6,298 | 6,352 | 1,142 | 29 | 1,815 | 33,037 |
| Production costs excluding taxes | | 1,162 | 2,203 | 3,365 | 1,049 | 1,334 | 845 | 88 | 2 | 266 | 6,949 |
| Taxes other than income taxes | | 1,681 | 580 | 2,261 | 54 | 41 | 386 | 4 | 2 | 5 | 2,753 |
| Exploration expenses | | 62 | 614 | 676 | 172 | 128 | 107 | 77 | 46 | 10 | 1,216 |
| Depreciation, depletion and amortization | | 428 | 3,200 | 3,628 | 1,312 | 1,006 | 1,051 | 29 | 1 | - | 7,027 |
| Impairments | | - | 2 | 2 | 216 | 301 | 3 | - | - | 43 | 565 |
| Other related expenses | | (121) | 72 | (49) | 41 | (83) | 209 | 7 | 20 | 76 | 221 |
| Accretion | | 54 | 74 | 128 | 59 | 200 | 24 | - | - | 5 | 416 |
| | | 3,276 | 1,449 | 4,725 | (238) | 3,371 | 3,727 | 937 | (42) | 1,410 | 13,890 |
| Provision for income taxes | | 1,168 | 491 | 1,659 | (270) | 2,262 | 1,509 | 924 | 13 | 251 | 6,348 |
| Results of operations | $ | 2,108 | 958 | 3,066 | 32 | 1,109 | 2,218 | 13 | (55) | 1,159 | 7,542 |
| | | | | | | | | | | | |
| *Equity affiliates* | | | | | | | | | | | |
| Sales | $ | - | - | - | 1,848 | - | 903 | - | 117 | - | 2,868 |
| Transfers | | - | - | - | - | - | 1,443 | - | - | - | 1,443 |
| Transportation costs | | - | - | - | - | - | - | - | - | - | - |
| Other revenues | | - | - | - | 6 | - | 22 | - | - | - | 28 |
| Total revenues | | - | - | - | 1,854 | - | 2,368 | - | 117 | - | 4,339 |
| Production costs excluding taxes | | - | - | - | 593 | - | 150 | - | 21 | - | 764 |
| Taxes other than income taxes | | - | - | - | 12 | - | 1,169 | - | 59 | - | 1,240 |
| Exploration expenses | | - | - | - | 22 | 30 | 8 | - | - | - | 60 |
| Depreciation, depletion and amortization | | - | - | - | 231 | - | 137 | - | 11 | - | 379 |
| Impairments | | - | - | - | - | - | - | - | - | - | - |
| Other related expenses | | - | - | - | 7 | - | (3) | - | 14 | - | 18 |
| Accretion | | - | - | - | 5 | - | 4 | - | 1 | - | 10 |
| | | - | - | - | 984 | (30) | 903 | - | 11 | - | 1,868 |
| Provision for income taxes | | - | - | - | 248 | - | (17) | - | 1 | - | 232 |
| Results of operations | $ | - | - | - | 736 | (30) | 920 | - | 10 | - | 1,636 |

## Statistics

| **Net Production** | **2015** | 2014 | 2013 |
|---|---|---|---|
| | Thousands of Barrels Daily | | |
| **Crude Oil** | | | |
| *Consolidated operations* | | | |
| Alaska | **158** | 162 | 178 |
| Lower 48 | **206** | 188 | 152 |
| United States | **364** | 350 | 330 |
| Canada | **12** | 13 | 13 |
| Europe | **120** | 126 | 113 |
| Asia Pacific/Middle East | **91** | 79 | 80 |
| Africa | **-** | 8 | 26 |
| Total consolidated operations | **587** | 576 | 562 |
| *Equity affiliates* | | | |
| Asia Pacific/Middle East | **14** | 15 | 15 |
| Other areas | **4** | 4 | 4 |
| Total equity affiliates | **18** | 19 | 19 |
| Total continuing operations | **605** | 595 | 581 |
| Discontinued operations | **-** | 5 | 18 |
| Total company | **605** | 600 | 599 |
| **Natural Gas Liquids** | | | |
| *Consolidated operations* | | | |
| Alaska | **13** | 13 | 15 |
| Lower 48 | **94** | 97 | 91 |
| United States | **107** | 110 | 106 |
| Canada | **26** | 23 | 25 |
| Europe | **7** | 8 | 6 |
| Asia Pacific/Middle East | **9** | 10 | 12 |
| Total consolidated operations | **149** | 151 | 149 |
| *Equity affiliates*—Asia Pacific/Middle East | **7** | 8 | 7 |
| Total continuing operations | **156** | 159 | 156 |
| Discontinued operations | **-** | 1 | 3 |
| Total company | **156** | 160 | 159 |
| **Bitumen** | | | |
| *Consolidated operations*—Canada | **13** | 12 | 13 |
| *Equity affiliates*—Canada | **138** | 117 | 96 |
| Total company | **151** | 129 | 109 |
| **Natural Gas** | Millions of Cubic Feet Daily | | |
| *Consolidated operations* | | | |
| Alaska | **42** | 49 | 43 |
| Lower 48 | **1,472** | 1,491 | 1,490 |
| United States | **1,514** | 1,540 | 1,533 |
| Canada | **715** | 711 | 775 |
| Europe | **475** | 461 | 416 |
| Asia Pacific/Middle East | **717** | 723 | 709 |
| Africa | **1** | 3 | 25 |
| Total consolidated operations | **3,422** | 3,438 | 3,458 |
| *Equity affiliates*—Asia Pacific/Middle East | **638** | 505 | 481 |
| Total continuing operations | **4,060** | 3,943 | 3,939 |
| Discontinued operations | **-** | 88 | 129 |
| Total company | **4,060** | 4,031 | 4,068 |

| Average Sales Prices | 2015 | 2014 | 2013 |
|---|---|---|---|
| **Crude Oil Per Barrel** | | | |
| *Consolidated operations* | | | |
| Alaska | $ **41.84** | 87.21 | 97.27 |
| Lower 48 | **42.62** | 84.18 | 93.79 |
| United States | **42.27** | 85.63 | 95.69 |
| Canada | **39.52** | 77.87 | 79.73 |
| Europe | **52.75** | 99.56 | 110.56 |
| Asia Pacific/Middle East | **49.70** | 95.32 | 104.78 |
| Africa | **60.79** | 86.71 | 107.21 |
| Total international | **50.79** | 96.48 | 106.43 |
| Total consolidated operations | **45.48** | 89.72 | 100.11 |
| *Equity affiliates* | | | |
| Asia Pacific/Middle East | **53.12** | 99.01 | 105.44 |
| Other areas | **37.21** | 64.14 | 72.43 |
| Total equity affiliates | **49.92** | 91.48 | 97.92 |
| Total continuing operations | **45.61** | 89.77 | 100.04 |
| *Discontinued operations* | **-** | 110.61 | 109.72 |
| **Natural Gas Liquids Per Barrel** | | | |
| *Consolidated operations* | | | |
| Lower 48 | $ **14.01** | 30.74 | 31.48 |
| United States | **14.01** | 30.74 | 31.48 |
| Canada | **17.02** | 46.23 | 47.19 |
| Europe | **27.56** | 52.65 | 58.36 |
| Asia Pacific/Middle East | **37.78** | 69.36 | 73.82 |
| Total international | **23.21** | 53.26 | 56.52 |
| Total consolidated operations | **16.83** | 37.45 | 39.60 |
| *Equity affiliates*—Asia Pacific/Middle East | **35.79** | 67.20 | 73.31 |
| Total continuing operations | **17.79** | 38.99 | 41.42 |
| *Discontinued operations* | **-** | 13.41 | 14.58 |
| **Bitumen Per Barrel** | | | |
| *Consolidated operations*—Canada | $ **20.13** | 60.03 | 55.25 |
| *Equity affiliates*—Canada | **18.58** | 54.62 | 53.00 |
| **Natural Gas Per Thousand Cubic Feet** | | | |
| *Consolidated operations* | | | |
| Alaska | $ **4.33** | 5.42 | 4.35 |
| Lower 48 | **2.43** | 4.29 | 3.50 |
| United States | **2.47** | 4.32 | 3.52 |
| Canada | **1.91** | 4.13 | 2.92 |
| Europe | **7.14** | 9.29 | 10.68 |
| Asia Pacific/Middle East | **6.08** | 9.64 | 10.46 |
| Africa | **-** | 3.40 | 5.38 |
| Total international | **4.78** | 7.48 | 7.40 |
| Total consolidated operations | **3.77** | 6.07 | 5.68 |
| *Equity affiliates*—Asia Pacific/Middle East | **4.83** | 9.79 | 8.98 |
| Total continuing operations | **3.93** | 6.54 | 6.09 |
| *Discontinued operations* | **-** | 2.53 | 2.60 |

*Average sales prices for Alaska crude oil and Asia Pacific/Middle East natural gas above reflect a reduction for transportation costs in which we have an ownership interest that are incurred subsequent to the terminal point of the production function. Accordingly, the average sales prices differ from those discussed in Item 7 of Management's Discussion and Analysis of Financial Condition and Results of Operations.*

| | | 2015 | 2014 | 2013 |
|---|---|---|---|---|
| **Average Production Costs Per Barrel of Oil Equivalent[(1)]** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **19.12** | 18.04 | 15.92 |
| Lower 48 | | **12.17** | 12.76 | 12.29 |
| United States | | **13.88** | 14.11 | 13.34 |
| Canada | | **14.88** | 18.14 | 15.97 |
| Europe | | **15.05** | 18.31 | 19.34 |
| Asia Pacific/Middle East | | **10.20** | 12.97 | 11.02 |
| Africa | | **-** | 28.42 | 8.04 |
| Total international | | **13.41** | 16.52 | 14.93 |
| Total consolidated continuing operations | | **13.67** | 15.20 | 14.08 |
| *Equity affiliates* | | | | |
| Canada | | **9.41** | 15.24 | 16.92 |
| Asia Pacific/Middle East | | **5.31** | 5.66 | 4.03 |
| Other areas | | **8.90** | 12.33 | 14.38 |
| Total equity affiliates | | **7.46** | 10.69 | 10.36 |
| *Discontinued operations* | | **-** | 16.70 | 16.95 |
| **Average Production Costs Per Barrel—Bitumen** | | | | |
| *Consolidated operations*—Canada | $ | **37.30** | 66.89 | 43.84 |
| *Equity affiliates*—Canada | | **9.41** | 15.24 | 16.92 |
| **Taxes Other Than Income Taxes Per Barrel of Oil Equivalent** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **4.33** | 12.61 | 23.03 |
| Lower 48 | | **1.80** | 3.60 | 3.24 |
| United States | | **2.42** | 5.90 | 8.96 |
| Canada | | **1.00** | 1.02 | 0.82 |
| Europe | | **0.46** | 0.57 | 0.59 |
| Asia Pacific/Middle East | | **0.41** | 3.90 | 5.04 |
| Africa | | **-** | 1.71 | 0.37 |
| Total international | | **0.62** | 1.89 | 2.19 |
| Total consolidated continuing operations | | **1.61** | 4.08 | 5.79 |
| *Equity affiliates* | | | | |
| Canada | | **0.30** | 0.33 | 0.34 |
| Asia Pacific/Middle East | | **15.48** | 31.08 | 31.40 |
| Other areas | | **8.90** | 34.93 | 40.41 |
| Total equity affiliates | | **7.62** | 15.37 | 16.82 |
| *Discontinued operations* | | **-** | 1.04 | 0.32 |
| **Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **8.43** | 6.33 | 5.86 |
| Lower 48 | | **21.07** | 18.82 | 17.86 |
| United States | | **17.96** | 15.63 | 14.38 |
| Canada | | **12.52** | 15.08 | 19.97 |
| Europe | | **24.00** | 23.07 | 14.58 |
| Asia Pacific/Middle East | | **16.53** | 14.68 | 13.71 |
| Africa | | **-** | 2.05 | 2.65 |
| Total international | | **17.98** | 17.59 | 15.29 |
| Total consolidated continuing operations | | **17.97** | 16.52 | 14.81 |
| *Equity affiliates* | | | | |
| Canada | | **7.29** | 7.89 | 6.59 |
| Asia Pacific/Middle East | | **4.22** | 4.38 | 3.68 |
| Other areas | | **3.42** | 4.79 | 7.53 |
| Total equity affiliates | | **5.77** | 6.19 | 5.14 |
| *Discontinued operations* | | **-** | - | - |

*(1)Includes bitumen.*

**Development and Exploration Activities**

The following two tables summarize our net interest in productive and dry exploratory and development wells in the years ended December 31, 2015, 2014 and 2013. A "development well" is a well drilled within the proved area of a reservoir to the depth of a stratigraphic horizon known to be productive. An "exploratory well" is a well drilled to find and produce crude oil or natural gas in an unknown field or a new reservoir within a proven field. Excluded from the exploratory well count are stratigraphic-type exploratory wells, primarily relating to oil sands delineation wells located in Canada and coalbed methane test wells located in Asia Pacific/Middle East.

| **Net Wells Completed** | Productive | | | Dry | | |
|---|---|---|---|---|---|---|
| | **2015** | 2014 | 2013 | **2015** | 2014 | 2013 |
| **Exploratory**[(1) (2)] | | | | | | |
| *Consolidated operations* | | | | | | |
| Alaska | **-** | * | 2 | **-** | * | - |
| Lower 48 | **47** | 30 | 67 | **4** | 3 | 4 |
| United States | **47** | 30 | 69 | **4** | 3 | 4 |
| Canada | **16** | 9 | 5 | **3** | * | - |
| Europe | ***** | 1 | * | ***** | 1 | * |
| Asia Pacific/Middle East | **1** | 2 | 3 | **2** | * | * |
| Africa | ***** | * | - | ***** | * | * |
| Other areas | **-** | - | - | **-** | - | * |
| Total consolidated operations | **64** | 42 | 77 | **9** | 4 | 4 |
| *Equity affiliates* | | | | | | |
| Asia Pacific/Middle East | **19** | 36 | 2 | ***** | 2 | - |
| Total equity affiliates | **19** | 36 | 2 | **-** | 2 | - |
| | | | | | | |
| **Development** | | | | | | |
| *Consolidated operations* | | | | | | |
| Alaska | **18** | 8 | 6 | **-** | - | - |
| Lower 48 | **347** | 450 | 441 | **-** | 1 | - |
| United States | **365** | 458 | 447 | **-** | 1 | - |
| Canada | **47** | 98 | 61 | **-** | - | - |
| Europe | **10** | 7 | 5 | **-** | - | * |
| Asia Pacific/Middle East | **3** | 14 | 29 | ***** | - | - |
| Africa | **-** | 1 | 4 | **-** | - | - |
| Other areas | **-** | - | * | **-** | - | - |
| Total consolidated operations | **425** | 578 | 546 | **-** | 1 | - |
| *Equity affiliates* | | | | | | |
| Canada[(3)] | **22** | 38 | 25 | **-** | - | - |
| Asia Pacific/Middle East | **166** | 294 | 24 | **2** | 1 | * |
| Other areas | ***** | 1 | - | **-** | - | - |
| Total equity affiliates[(3)] | **188** | 333 | 49 | **2** | 1 | - |

*(1)Excludes net stratigraphic-type exploratory wells of 46, 90 and 149 for the years ended December 31, 2015, 2014 and 2013, respectively.*
*(2)This also includes net extension wells of 22, 49 and 55 for the years ended December 31, 2015, 2014 and 2013, respectively.*
*Extension wells are wells drilled in areas near or offsetting current production, or in areas where well density or production history have not achieved statistical certainty of results, primarily located in Asia Pacific/Middle East and the United States.*
*(3)Prior periods revised to conform to current period presentation.*
**Our total proportionate interest was less than one.*

The table below represents the status of our wells drilling at December 31, 2015, and includes wells in the process of drilling or in active completion. It also represents gross and net productive wells, including producing wells and wells capable of production at December 31, 2015.

| **Wells at December 31, 2015** | In Progress | | Productive* | | | |
|---|---|---|---|---|---|---|
| | | | Oil | | Gas | |
| | Gross | Net | Gross | Net | Gross | Net |
| *Consolidated operations* | | | | | | |
| Alaska | 2 | 1 | 1,740 | 777 | 29 | 17 |
| Lower 48 | 247 | 105 | 9,906 | 5,026 | 20,089 | 13,084 |
| United States | 249 | 106 | 11,646 | 5,803 | 20,118 | 13,101 |
| Canada | 122 | 65 | 1,010 | 549 | 4,788 | 3,278 |
| Europe | 22 | 3 | 461 | 82 | 189 | 71 |
| Asia Pacific/Middle East | 21 | 8 | 435 | 179 | 132 | 58 |
| Africa | 11 | 2 | 825 | 134 | 9 | 2 |
| Total consolidated operations | 425 | 184 | 14,377 | 6,747 | 25,236 | 16,510 |
| *Equity affiliates* | | | | | | |
| Canada | 181 | 91 | 409 | 205 | - | - |
| Asia Pacific/Middle East | 466 | 115 | - | - | 3,089 | 705 |
| Total equity affiliates | 647 | 206 | 409 | 205 | 3,089 | 705 |

**Includes 131 gross and 113 net multiple completion wells.*

| **Acreage at December 31, 2015** | Thousands of Acres | | | |
|---|---|---|---|---|
| | Developed | | Undeveloped | |
| | Gross | Net | Gross | Net |
| *Consolidated operations* | | | | |
| Alaska | 632 | 320 | 1,016 | 694 |
| Lower 48 | 4,814 | 3,903 | 12,436 | 10,334 |
| United States | 5,446 | 4,223 | 13,452 | 11,028 |
| Canada | 3,195 | 2,201 | 10,216 | 4,425 |
| Europe | 861 | 274 | 2,078 | 641 |
| Asia Pacific/Middle East | 4,258 | 1,811 | 11,702 | 5,906 |
| Africa | 358 | 59 | 16,834 | 3,666 |
| Other areas | - | - | 3,539 | 2,409 |
| Total consolidated operations | 14,118 | 8,568 | 57,821 | 28,075 |
| *Equity affiliates* | | | | |
| Canada | 51 | 21 | 658 | 277 |
| Asia Pacific/Middle East | 731 | 162 | 6,450 | 1,815 |
| Total equity affiliates | 782 | 183 | 7,108 | 2,092 |

## Costs Incurred

| Year Ended December 31 | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **2015** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Unproved property acquisition | $ - | 168 | 168 | 52 | - | - | - | - | 220 |
| Proved property acquisition | - | 5 | 5 | 1 | - | - | - | - | 6 |
| | - | 173 | 173 | 53 | - | - | - | - | 226 |
| Exploration | 87 | 1,369 | 1,456 | 298 | 107 | 118 | 394 | 47 | 2,420 |
| Development | 1,217 | 2,875 | 4,092 | 827 | 1,742 | 587 | 4 | - | 7,252 |
| | $ 1,304 | 4,417 | 5,721 | 1,178 | 1,849 | 705 | 398 | 47 | 9,898 |
| *Equity affiliates* | | | | | | | | | |
| Unproved property acquisition | $ - | - | - | - | - | - | - | - | - |
| Proved property acquisition | - | - | - | - | - | - | - | - | - |
| | - | - | - | - | - | - | - | - | - |
| Exploration | - | - | - | 17 | - | 57 | - | - | 74 |
| Development | - | - | - | 847 | - | 1,212 | - | 3 | 2,062 |
| | $ - | - | - | 864 | - | 1,269 | - | 3 | 2,136 |
| 2014 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Unproved property acquisition | $ - | 159 | 159 | 61 | 90 | - | 6 | - | 316 |
| Proved property acquisition | - | 10 | 10 | - | - | - | - | - | 10 |
| | - | 169 | 169 | 61 | 90 | - | 6 | - | 326 |
| Exploration | 130 | 1,347 | 1,477 | 332 | 243 | 166 | 556 | 58 | 2,832 |
| Development | 1,263 | 4,881 | 6,144 | 2,185 | 3,618 | 1,353 | 71 | - | 13,371 |
| | $ 1,393 | 6,397 | 7,790 | 2,578 | 3,951 | 1,519 | 633 | 58 | 16,529 |
| *Equity affiliates* | | | | | | | | | |
| Unproved property acquisition | $ - | - | - | - | - | 2 | - | - | 2 |
| Proved property acquisition | - | - | - | - | - | - | - | - | - |
| | - | - | - | - | - | 2 | - | - | 2 |
| Exploration | - | - | - | 23 | 36 | 89 | - | - | 148 |
| Development | - | - | - | 1,627 | - | 2,258 | - | 9 | 3,894 |
| | $ - | - | - | 1,650 | 36 | 2,349 | - | 9 | 4,044 |
| 2013 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Unproved property acquisition | $ 3 | 311 | 314 | 90 | - | 111 | 177 | 15 | 707 |
| Proved property acquisition | - | 4 | 4 | 10 | - | - | - | - | 14 |
| | 3 | 315 | 318 | 100 | - | 111 | 177 | 15 | 721 |
| Exploration | 159 | 1,156 | 1,315 | 294 | 240 | 321 | 136 | 49 | 2,355 |
| Development | 925 | 4,067 | 4,992 | 1,952 | 3,999 | 2,256 | 216 | 409 | 13,824 |
| | $ 1,087 | 5,538 | 6,625 | 2,346 | 4,239 | 2,688 | 529 | 473 | 16,900 |
| *Equity affiliates* | | | | | | | | | |
| Unproved property acquisition | $ - | - | - | 1 | - | 51 | - | - | 52 |
| Proved property acquisition | - | - | - | - | - | - | - | - | - |
| | - | - | - | 1 | - | 51 | - | - | 52 |
| Exploration | - | - | - | 59 | 31 | 101 | - | - | 191 |
| Development | - | - | - | 1,532 | - | 2,141 | - | 3 | 3,676 |
| | $ - | - | - | 1,592 | 31 | 2,293 | - | 3 | 3,919 |

## Capitalized Costs

| At December 31 | | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **2015** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Proved property | $ 17,007 | 45,256 | 62,263 | 16,552 | 26,851 | 16,254 | 873 | 3 | 122,796 |
| Unproved property | 1,609 | 2,414 | 4,023 | 1,418 | 330 | 781 | 823 | 35 | 7,410 |
| | 18,616 | 47,670 | 66,286 | 17,970 | 27,181 | 17,035 | 1,696 | 38 | 130,206 |
| Accumulated depreciation, depletion and amortization | 8,688 | 22,993 | 31,681 | 9,371 | 16,166 | 8,853 | 788 | 4 | 66,863 |
| | $ 9,928 | 24,677 | 34,605 | 8,599 | 11,015 | 8,182 | 908 | 34 | 63,343 |
| *Equity affiliates* | | | | | | | | | |
| Proved property | $ - | - | - | 8,763 | - | 8,693 | - | - | 17,456 |
| Unproved property | - | - | - | 906 | - | 3,178 | - | - | 4,084 |
| | - | - | - | 9,669 | - | 11,871 | - | - | 21,540 |
| Accumulated depreciation, depletion and amortization | - | - | - | 1,537 | - | 996 | - | - | 2,533 |
| | $ - | - | - | 8,132 | - | 10,875 | - | - | 19,007 |
| 2014 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Proved property | $ 15,686 | 47,390 | 63,076 | 22,831 | 27,933 | 15,730 | 870 | 8 | 130,448 |
| Unproved property | 1,724 | 2,938 | 4,662 | 1,975 | 432 | 927 | 923 | 32 | 8,951 |
| | 17,410 | 50,328 | 67,738 | 24,806 | 28,365 | 16,657 | 1,793 | 40 | 139,399 |
| Accumulated depreciation, depletion and amortization | 7,545 | 23,484 | 31,029 | 13,419 | 15,134 | 7,594 | 294 | 9 | 67,479 |
| | $ 9,865 | 26,844 | 36,709 | 11,387 | 13,231 | 9,063 | 1,499 | 31 | 71,920 |
| *Equity affiliates* | | | | | | | | | |
| Proved property | $ - | - | - | 9,506 | - | 8,855 | - | 220 | 18,581 |
| Unproved property | - | - | - | 1,150 | - | 3,474 | - | - | 4,624 |
| | - | - | - | 10,656 | - | 12,329 | - | 220 | 23,205 |
| Accumulated depreciation, depletion and amortization | - | - | - | 1,422 | - | 566 | - | 198 | 2,186 |
| | $ - | - | - | 9,234 | - | 11,763 | - | 22 | 21,019 |

**Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities**

In accordance with SEC and FASB requirements, amounts were computed using 12-month average prices (adjusted only for existing contractual terms) and end-of-year costs, appropriate statutory tax rates and a prescribed 10 percent discount factor. Twelve-month average prices are calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. For all years, continuation of year-end economic conditions was assumed. The calculations were based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, were not considered. The calculations also require assumptions as to the timing of future production of proved reserves and the timing and amount of future development costs, including dismantlement, and future production costs, including taxes other than income taxes.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

**Discounted Future Net Cash Flows**

| | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
| **2015** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| Future cash inflows | $ 44,054 | 42,575 | 86,629 | 22,317 | 27,782 | 19,368 | 13,875 | 169,971 |
| Less: | | | | | | | | |
| Future production costs | 32,732 | 21,638 | 54,370 | 13,103 | 10,574 | 7,529 | 1,422 | 86,998 |
| Future development costs | 9,885 | 12,967 | 22,852 | 6,471 | 12,793 | 2,884 | 437 | 45,437 |
| Future income tax provisions | - | 844 | 844 | - | 1,506 | 2,708 | 10,998 | 16,056 |
| Future net cash flows | 1,437 | 7,126 | 8,563 | 2,743 | 2,909 | 6,247 | 1,018 | 21,480 |
| 10 percent annual discount | (502) | 1,573 | 1,071 | 1,265 | 733 | 1,349 | 500 | 4,918 |
| Discounted future net cash flows | $ 1,939 | 5,553 | 7,492 | 1,478 | 2,176 | 4,898 | 518 | 16,562 |
| *Equity affiliates* | | | | | | | | |
| Future cash inflows | $ - | - | - | 36,211 | - | 34,257 | - | 70,468 |
| Less: | | | | | | | | |
| Future production costs | - | - | - | 16,417 | - | 17,874 | - | 34,291 |
| Future development costs | - | - | - | 11,869 | - | 2,391 | - | 14,260 |
| Future income tax provisions | - | - | - | 1,648 | - | 3,117 | - | 4,765 |
| Future net cash flows | - | - | - | 6,277 | - | 10,875 | - | 17,152 |
| 10 percent annual discount | - | - | - | 3,827 | - | 4,298 | - | 8,125 |
| Discounted future net cash flows | $ - | - | - | 2,450 | - | 6,577 | - | 9,027 |
| *Total company* | | | | | | | | |
| Discounted future net cash flows | $ 1,939 | 5,553 | 7,492 | 3,928 | 2,176 | 11,475 | 518 | 25,589 |

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| 2014 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Future cash inflows | $ 106,506 | 100,322 | 206,828 | 50,209 | 55,878 | 39,492 | 25,997 | - | 378,404 |
| Less: | | | | | | | | | |
| Future production costs | 57,924 | 37,872 | 95,796 | 21,342 | 16,372 | 12,555 | 1,338 | - | 147,403 |
| Future development costs | 10,815 | 19,666 | 30,481 | 10,400 | 14,194 | 2,985 | 437 | - | 58,497 |
| Future income tax provisions | 12,483 | 14,800 | 27,283 | 3,159 | 15,757 | 7,728 | 22,526 | - | 76,453 |
| Future net cash flows | 25,284 | 27,984 | 53,268 | 15,308 | 9,555 | 16,224 | 1,696 | - | 96,051 |
| 10 percent annual discount | 12,499 | 10,150 | 22,649 | 8,915 | 2,741 | 4,607 | 791 | - | 39,703 |
| Discounted future net cash flows | $ 12,785 | 17,834 | 30,619 | 6,393 | 6,814 | 11,617 | 905 | - | 56,348 |
| *Equity affiliates* | | | | | | | | | |
| Future cash inflows | $ - | - | - | 88,716 | - | 61,480 | - | 357 | 150,553 |
| Less: | | | | | | | | | |
| Future production costs | - | - | - | 25,455 | - | 27,274 | - | 276 | 53,005 |
| Future development costs | - | - | - | 11,595 | - | 3,007 | - | 16 | 14,618 |
| Future income tax provisions | - | - | - | 12,322 | - | 7,225 | - | 10 | 19,557 |
| Future net cash flows | - | - | - | 39,344 | - | 23,974 | - | 55 | 63,373 |
| 10 percent annual discount | - | - | - | 25,601 | - | 10,897 | - | 6 | 36,504 |
| Discounted future net cash flows | $ - | - | - | 13,743 | - | 13,077 | - | 49 | 26,869 |
| *Total company* | | | | | | | | | |
| Discounted future net cash flows | $ 12,785 | 17,834 | 30,619 | 20,136 | 6,814 | 24,694 | 905 | 49 | 83,217 |

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| 2013 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Future cash inflows | $ 120,384 | 93,276 | 213,660 | 39,695 | 69,654 | 43,827 | 33,055 | - | 399,891 |
| Less: | | | | | | | | | |
| Future production costs | 61,636 | 34,344 | 95,980 | 22,435 | 16,902 | 14,567 | 4,148 | - | 154,032 |
| Future development costs | 12,282 | 15,833 | 28,115 | 12,228 | 14,821 | 3,250 | 695 | - | 59,109 |
| Future income tax provisions | 16,356 | 14,810 | 31,166 | 401 | 24,706 | 8,388 | 25,371 | - | 90,032 |
| Future net cash flows | 30,110 | 28,289 | 58,399 | 4,631 | 13,225 | 17,622 | 2,841 | - | 96,718 |
| 10 percent annual discount | 16,187 | 11,217 | 27,404 | 2,881 | 4,298 | 5,046 | 1,086 | - | 40,715 |
| Discounted future net cash flows | $ 13,923 | 17,072 | 30,995 | 1,750 | 8,927 | 12,576 | 1,755 | - | 56,003 |
| *Equity affiliates* | | | | | | | | | |
| Future cash inflows | $ - | - | - | 72,327 | - | 55,327 | - | 296 | 127,950 |
| Less: | | | | | | | | | |
| Future production costs | - | - | - | 24,953 | - | 26,356 | - | 233 | 51,542 |
| Future development costs | - | - | - | 10,673 | - | 2,616 | - | 13 | 13,302 |
| Future income tax provisions | - | - | - | 8,776 | - | 5,471 | - | 6 | 14,253 |
| Future net cash flows | - | - | - | 27,925 | - | 20,884 | - | 44 | 48,853 |
| 10 percent annual discount | - | - | - | 17,643 | - | 9,697 | - | 4 | 27,344 |
| Discounted future net cash flows | $ - | - | - | 10,282 | - | 11,187 | - | 40 | 21,509 |
| *Total company* | | | | | | | | | |
| Discounted future net cash flows | $ 13,923 | 17,072 | 30,995 | 12,032 | 8,927 | 23,763 | 1,755 | 40 | 77,512 |

**Sources of Change in Discounted Future Net Cash Flows**

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Consolidated Operations | | | Equity Affiliates | | | Total Company | | |
| | **2015** | 2014 | 2013 | **2015** | 2014 | 2013 | **2015** | 2014 | 2013 |
| Discounted future net cash flows at the beginning of the year | **$ 56,348** | 56,003 | 53,949 | **26,869** | 21,509 | 19,244 | **83,217** | 77,512 | 73,193 |
| Changes during the year | | | | | | | | | |
| Revenues less production costs for the year | **(8,158)** | (19,571) | (21,250) | **(966)** | (2,748) | (2,307) | **(9,124)** | (22,319) | (23,557) |
| Net change in prices and production costs | **(82,923)** | (9,243) | (611) | **(27,670)** | 4,517 | (1,645) | **(110,593)** | (4,726) | (2,256) |
| Extensions, discoveries and improved recovery, less estimated future costs | **1,791** | 7,033 | 15,796 | **319** | 1,822 | 1,804 | **2,110** | 8,855 | 17,600 |
| Development costs for the year | **6,854** | 11,785 | 11,640 | **2,050** | 3,669 | 3,675 | **8,904** | 15,454 | 15,315 |
| Changes in estimated future development costs | **2,073** | (7,771) | (9,760) | **(784)** | (1,829) | (3,167) | **1,289** | (9,600) | (12,927) |
| Purchases of reserves in place, less estimated future costs | **-** | - | 2 | **-** | 5 | - | **-** | 5 | 2 |
| Sales of reserves in place, less estimated future costs | **(424)** | (1,280) | (5,997) | **(38)** | - | - | **(462)** | (1,280) | (5,997) |
| Revisions of previous quantity estimates | **(1,790)** | 1,348 | 4,317 | **938** | (1,166) | 2,357 | **(852)** | 182 | 6,674 |
| Accretion of discount | **9,342** | 10,045 | 9,732 | **3,297** | 2,648 | 2,331 | **12,639** | 12,693 | 12,063 |
| Net change in income taxes | **33,449** | 7,999 | (1,815) | **5,012** | (1,558) | (783) | **38,461** | 6,441 | (2,598) |
| Total changes | **(39,786)** | 345 | 2,054 | **(17,842)** | 5,360 | 2,265 | **(57,628)** | 5,705 | 4,319 |
| Discounted future net cash flows at year end | **$ 16,562** | 56,348 | 56,003 | **9,027** | 26,869 | 21,509 | **25,589** | 83,217 | 77,512 |

- The net change in prices and production costs is the beginning-of-year reserve-production forecast multiplied by the net annual change in the per-unit sales price and production cost, discounted at 10 percent.

- Purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.

- Revisions of previous quantity estimates are calculated using production forecast changes for the year, including changes in the timing of production, multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.

- The accretion of discount is 10 percent of the prior year’s discounted future cash inflows, less future production and development costs.

- The net change in income taxes is the annual change in the discounted future income tax provisions.

**Selected Quarterly Financial Data** (Unaudited)

| | Millions of Dollars | | | | Per Share of Common Stock | |
|---|---|---|---|---|---|---|
| | | | | | Net Income (Loss) Attributable to ConocoPhillips | |
| | Sales and Other Operating Revenues | Income (Loss) From Continuing Operations Before Income Taxes | Net Income (Loss) | Net Income (Loss) Attributable to ConocoPhillips | Basic | Diluted |
| **2015** | | | | | | |
| First | **$ 7,716** | **(356)** | **286** | **272** | **0.22** | **0.22** |
| Second | **8,293** | **(91)** | **(164)** | **(179)** | **(0.15)** | **(0.15)** |
| Third | **7,262** | **(1,741)** | **(1,056)** | **(1,071)** | **(0.87)** | **(0.87)** |
| Fourth | **6,293** | **(5,051)** | **(3,437)** | **(3,450)** | **(2.78)** | **(2.78)** |
| 2014 | | | | | | |
| First | $ 15,415 | 3,698 | 2,137 | 2,123 | 1.72 | 1.71 |
| Second | 13,821 | 3,460 | 2,098 | 2,081 | 1.68 | 1.67 |
| Third | 12,080 | 2,553 | 2,727 | 2,704 | 2.18 | 2.17 |
| Fourth | 11,208 | (321) | (24) | (39) | (0.03) | (0.03) |

*For additional information on the commodity price environment, see the Business Environment and Executive Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations.*

**Supplementary Information—Condensed Consolidating Financial Information**

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company and ConocoPhillips Canada Funding Company I, with respect to publicly held debt securities. ConocoPhillips Company is 100 percent owned by ConocoPhillips. ConocoPhillips Australia Funding Company and ConocoPhillips Canada Funding Company I are indirect, 100 percent owned subsidiaries of ConocoPhillips Company. ConocoPhillips and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Australia Funding Company and ConocoPhillips Canada Funding Company I, with respect to their publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial information presents the results of operations, financial position and cash flows for:

- ConocoPhillips, ConocoPhillips Company and ConocoPhillips Canada Funding Company I (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).
- All other nonguarantor subsidiaries of ConocoPhillips.
- The consolidating adjustments necessary to present ConocoPhillips' results on a consolidated basis.

In May 2014, we filed a universal shelf registration statement with the SEC under which ConocoPhillips, as a well-known seasoned issuer, has the ability to issue and sell an indeterminate amount of various types of debt and equity securities, with certain debt securities guaranteed by ConocoPhillips Company. Also as part of that registration statement, ConocoPhillips Trust I and ConocoPhillips Trust II have the ability to issue and sell preferred trust securities, guaranteed by ConocoPhillips. ConocoPhillips Trust I and ConocoPhillips Trust II have not issued any trust-preferred securities under this registration statement, and thus have no assets or liabilities. Accordingly, columns for these two trusts are not included in the condensed consolidating financial information.

During 2013, ConocoPhillips Australia Funding Company's guaranteed, publicly held debt was repaid. Beginning in 2014, financial information for ConocoPhillips Australia Funding Company is presented in the "All Other Subsidiaries" column of our condensed consolidating financial information.

In 2014, ConocoPhillips received $34.5 billion in dividends from ConocoPhillips Company to settle certain accumulated intercompany balances. This consisted of a $17.5 billion distribution of earnings and a $17 billion return of capital. These transactions had no impact on our consolidated financial statements.

In 2015, ConocoPhillips received a $3.5 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In February 2016, ConocoPhillips received a $2.3 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction will be reflected in the first quarter 2016 Condensed Consolidating Financial Information for ConocoPhillips and ConocoPhillips Company and is expected to have no impact on our consolidated financial statements.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes.

| Income Statement | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
|---|---|---|---|---|---|---|
| | Millions of Dollars | | | | | |
| | Year Ended December 31, 2015 | | | | | |
| **Revenues and Other Income** | | | | | | |
| Sales and other operating revenues | $ - | 11,473 | - | 18,091 | - | 29,564 |
| Equity in earnings of affiliates | (4,081) | (1,950) | - | 1,364 | 5,322 | 655 |
| Gain on dispositions | - | 332 | - | 259 | - | 591 |
| Other income | - | 12 | - | 113 | - | 125 |
| Intercompany revenues | 74 | 341 | 246 | 3,365 | (4,026) | - |
| Total Revenues and Other Income | (4,007) | 10,208 | 246 | 23,192 | 1,296 | 30,935 |
| **Costs and Expenses** | | | | | | |
| Purchased commodities | - | 9,905 | - | 5,838 | (3,317) | 12,426 |
| Production and operating expenses | - | 1,469 | - | 5,585 | (38) | 7,016 |
| Selling, general and administrative expenses | 9 | 744 | 1 | 209 | (10) | 953 |
| Exploration expenses | - | 2,093 | - | 2,099 | - | 4,192 |
| Depreciation, depletion and amortization | - | 1,201 | - | 7,912 | - | 9,113 |
| Impairments | - | 15 | - | 2,230 | - | 2,245 |
| Taxes other than income taxes | - | 173 | - | 728 | - | 901 |
| Accretion on discounted liabilities | - | 58 | - | 425 | - | 483 |
| Interest and debt expense | 485 | 423 | 226 | 447 | (661) | 920 |
| Foreign currency transaction (gains) losses | 114 | 1 | (708) | 518 | - | (75) |
| Total Costs and Expenses | 608 | 16,082 | (481) | 25,991 | (4,026) | 38,174 |
| Income (loss) from continuing operations before income taxes | (4,615) | (5,874) | 727 | (2,799) | 5,322 | (7,239) |
| Provision (benefit) for income taxes | (187) | (1,793) | 21 | (909) | - | (2,868) |
| Net income (loss) | (4,428) | (4,081) | 706 | (1,890) | 5,322 | (4,371) |
| Less: net income attributable to noncontrolling interests | - | - | - | (57) | - | (57) |
| **Net Income (Loss) Attributable to ConocoPhillips** | $ (4,428) | (4,081) | 706 | (1,947) | 5,322 | (4,428) |
| **Comprehensive Income (Loss) Attributable to ConocoPhillips** | $ (8,773) | (8,426) | 71 | (6,705) | 15,060 | (8,773) |

| Income Statement | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
|---|---|---|---|---|---|---|
| | Year Ended December 31, 2014 | | | | | |
| **Revenues and Other Income** | | | | | | |
| Sales and other operating revenues | $ - | 20,083 | - | 32,441 | - | 52,524 |
| Equity in earnings of affiliates | 6,108 | 8,090 | - | 2,932 | (14,601) | 2,529 |
| Gain on dispositions | - | 9 | - | 89 | - | 98 |
| Other income (loss) | (6) | 67 | - | 305 | - | 366 |
| Intercompany revenues | 79 | 465 | 283 | 5,883 | (6,710) | - |
| Total Revenues and Other Income | 6,181 | 28,714 | 283 | 41,650 | (21,311) | 55,517 |
| **Costs and Expenses** | | | | | | |
| Purchased commodities | - | 17,591 | - | 10,415 | (5,907) | 22,099 |
| Production and operating expenses | - | 2,600 | - | 6,368 | (59) | 8,909 |
| Selling, general and administrative expenses | 9 | 575 | 1 | 166 | (16) | 735 |
| Exploration expenses | - | 1,036 | - | 1,009 | - | 2,045 |
| Depreciation, depletion and amortization | - | 1,059 | - | 7,270 | - | 8,329 |
| Impairments | - | 127 | - | 729 | - | 856 |
| Taxes other than income taxes | - | 285 | - | 1,803 | - | 2,088 |
| Accretion on discounted liabilities | - | 58 | - | 426 | - | 484 |
| Interest and debt expense | 571 | 299 | 231 | 275 | (728) | 648 |
| Foreign currency transaction (gains) losses | 62 | 10 | (372) | 234 | - | (66) |
| Total Costs and Expenses | 642 | 23,640 | (140) | 28,695 | (6,710) | 46,127 |
| Income from continuing operations before income taxes | 5,539 | 5,074 | 423 | 12,955 | (14,601) | 9,390 |
| Provision (benefit) for income taxes | (199) | (1,034) | 19 | 4,797 | - | 3,583 |
| **Income From Continuing Operations** | 5,738 | 6,108 | 404 | 8,158 | (14,601) | 5,807 |
| Income from discontinued operations | 1,131 | 1,131 | - | 113 | (1,244) | 1,131 |
| Net income | 6,869 | 7,239 | 404 | 8,271 | (15,845) | 6,938 |
| Less: net income attributable to noncontrolling interests | - | - | - | (69) | - | (69) |
| **Net Income Attributable to ConocoPhillips** | $ 6,869 | 7,239 | 404 | 8,202 | (15,845) | 6,869 |
| **Comprehensive Income Attributable to ConocoPhillips** | $ 2,965 | 3,335 | 58 | 4,589 | (7,982) | 2,965 |

| Income Statement | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Australia Funding Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
|---|---|---|---|---|---|---|---|
| | Millions of Dollars | | | | | | |
| | Year Ended December 31, 2013 | | | | | | |
| **Revenues and Other Income** | | | | | | | |
| Sales and other operating revenues | $ - | 18,186 | - | - | 36,227 | - | 54,413 |
| Equity in earnings of affiliates | 8,374 | 9,200 | - | - | 2,611 | (17,966) | 2,219 |
| Gain on dispositions | - | 364 | - | - | 878 | - | 1,242 |
| Other income | 2 | 271 | - | - | 101 | - | 374 |
| Intercompany revenues | 82 | 458 | 13 | 305 | 4,948 | (5,806) | - |
| Total Revenues and Other Income | 8,458 | 28,479 | 13 | 305 | 44,765 | (23,772) | 58,248 |
| **Costs and Expenses** | | | | | | | |
| Purchased commodities | - | 15,779 | - | - | 11,812 | (4,948) | 22,643 |
| Production and operating expenses | - | 1,492 | - | - | 5,756 | (10) | 7,238 |
| Selling, general and administrative expenses | 11 | 623 | - | 1 | 238 | (19) | 854 |
| Exploration expenses | - | 659 | - | - | 573 | - | 1,232 |
| Depreciation, depletion and amortization | - | 907 | - | - | 6,527 | - | 7,434 |
| Impairments | - | 4 | - | - | 525 | - | 529 |
| Taxes other than income taxes | - | 236 | - | - | 2,648 | - | 2,884 |
| Accretion on discounted liabilities | - | 56 | - | - | 378 | - | 434 |
| Interest and debt expense | 630 | 327 | 12 | 235 | 237 | (829) | 612 |
| Foreign currency transaction (gains) losses | 52 | 3 | - | (349) | 236 | - | (58) |
| Total Costs and Expenses | 693 | 20,086 | 12 | (113) | 28,930 | (5,806) | 43,802 |
| Income from continuing operations before income taxes | 7,765 | 8,393 | 1 | 418 | 15,835 | (17,966) | 14,446 |
| Provision (benefit) for income taxes | (213) | 19 | - | 31 | 6,572 | - | 6,409 |
| **Income From Continuing Operations** | 7,978 | 8,374 | 1 | 387 | 9,263 | (17,966) | 8,037 |
| Income from discontinued operations | 1,178 | 1,178 | - | - | 1,178 | (2,356) | 1,178 |
| Net income | 9,156 | 9,552 | 1 | 387 | 10,441 | (20,322) | 9,215 |
| Less: net income attributable to noncontrolling interests | - | - | - | - | (59) | - | (59) |
| **Net Income Attributable to ConocoPhillips** | $ 9,156 | 9,552 | 1 | 387 | 10,382 | (20,322) | 9,156 |
| **Comprehensive Income Attributable to ConocoPhillips** | $ 7,071 | 7,467 | 1 | 99 | 7,782 | (15,349) | 7,071 |

| Balance Sheet | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
|---|---|---|---|---|---|---|
| | Millions of Dollars | | | | | |
| | At December 31, 2015 | | | | | |
| **Assets** | | | | | | |
| Cash and cash equivalents | $ - | 4 | 15 | 2,349 | - | 2,368 |
| Accounts and notes receivable | 21 | 2,905 | 21 | 7,228 | (5,661) | 4,514 |
| Inventories | - | 142 | - | 982 | - | 1,124 |
| Prepaid expenses and other current assets | 2 | 206 | 252 | 589 | (266) | 783 |
| Total Current Assets | 23 | 3,257 | 288 | 11,148 | (5,927) | 8,789 |
| Investments, loans and long-term receivables* | 43,532 | 64,015 | 3,264 | 27,839 | (117,464) | 21,186 |
| Net properties, plants and equipment | - | 8,110 | - | 58,336 | - | 66,446 |
| Other assets | 7 | 950 | 233 | 1,158 | (1,285) | 1,063 |
| Total Assets | $ 43,562 | 76,332 | 3,785 | 98,481 | (124,676) | 97,484 |
| **Liabilities and Stockholders' Equity** | | | | | | |
| Accounts payable | $ - | 5,684 | 13 | 4,897 | (5,661) | 4,933 |
| Short-term debt | (9) | 1 | 1,255 | 180 | - | 1,427 |
| Accrued income and other taxes | - | 62 | - | 437 | - | 499 |
| Employee benefit obligations | - | 629 | - | 258 | - | 887 |
| Other accruals | 170 | 465 | 52 | 1,087 | (264) | 1,510 |
| Total Current Liabilities | 161 | 6,841 | 1,320 | 6,859 | (5,925) | 9,256 |
| Long-term debt | 7,518 | 10,660 | 1,716 | 3,559 | - | 23,453 |
| Asset retirement obligations and accrued environmental costs | - | 1,107 | - | 8,473 | - | 9,580 |
| Deferred income taxes | - | - | - | 11,814 | (815) | 10,999 |
| Employee benefit obligations | - | 1,760 | - | 526 | - | 2,286 |
| Other liabilities and deferred credits* | 2,681 | 7,291 | 667 | 15,181 | (23,992) | 1,828 |
| Total Liabilities | 10,360 | 27,659 | 3,703 | 46,412 | (30,732) | 57,402 |
| Retained earnings | 29,892 | 17,366 | (389) | 15,177 | (25,632) | 36,414 |
| Other common stockholders' equity | 3,310 | 31,307 | 471 | 36,572 | (68,312) | 3,348 |
| Noncontrolling interests | - | - | - | 320 | - | 320 |
| Total Liabilities and Stockholders' Equity | $ 43,562 | 76,332 | 3,785 | 98,481 | (124,676) | 97,484 |

| Balance Sheet | At December 31, 2014 | | | | | |
|---|---|---|---|---|---|---|
| **Assets** | | | | | | |
| Cash and cash equivalents | $ - | 770 | 7 | 4,285 | - | 5,062 |
| Accounts and notes receivable | 20 | 2,813 | 22 | 6,671 | (2,719) | 6,807 |
| Inventories | - | 281 | - | 1,050 | - | 1,331 |
| Prepaid expenses and other current assets | 6 | 754 | 15 | 1,138 | (45) | 1,868 |
| Total Current Assets | 26 | 4,618 | 44 | 13,144 | (2,764) | 15,068 |
| Investments, loans and long-term receivables* | 55,568 | 70,732 | 3,965 | 32,467 | (137,593) | 25,139 |
| Net properties, plants and equipment | - | 9,730 | - | 65,714 | - | 75,444 |
| Other assets | 40 | 67 | 208 | 1,338 | (765) | 888 |
| Total Assets | $ 55,634 | 85,147 | 4,217 | 112,663 | (141,122) | 116,539 |
| **Liabilities and Stockholders' Equity** | | | | | | |
| Accounts payable | $ 1 | 4,149 | 14 | 6,581 | (2,719) | 8,026 |
| Short-term debt | (5) | 6 | 5 | 176 | - | 182 |
| Accrued income and other taxes | - | 117 | - | 934 | - | 1,051 |
| Employee benefit obligations | - | 595 | - | 283 | - | 878 |
| Other accruals | 170 | 337 | 71 | 868 | (46) | 1,400 |
| Total Current Liabilities | 166 | 5,204 | 90 | 8,842 | (2,765) | 11,537 |
| Long-term debt | 7,541 | 8,197 | 2,974 | 3,671 | - | 22,383 |
| Asset retirement obligations and accrued environmental costs | - | 1,328 | - | 9,319 | - | 10,647 |
| Deferred income taxes | - | 265 | - | 14,811 | (6) | 15,070 |
| Employee benefit obligations | - | 2,162 | - | 802 | - | 2,964 |
| Other liabilities and deferred credits* | 2,577 | 7,391 | 1,142 | 17,218 | (26,663) | 1,665 |
| Total Liabilities | 10,284 | 24,547 | 4,206 | 54,663 | (29,434) | 64,266 |
| Retained earnings | 37,983 | 21,448 | (1,096) | 17,355 | (31,186) | 44,504 |
| Other common stockholders' equity | 7,367 | 39,152 | 1,107 | 40,283 | (80,502) | 7,407 |
| Noncontrolling interests | - | - | - | 362 | - | 362 |
| Total Liabilities and Stockholders' Equity | $ 55,634 | 85,147 | 4,217 | 112,663 | (141,122) | 116,539 |

**Includes intercompany loans.*

| Statement of Cash Flows | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, 2015 | | | | | |
| | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
| **Cash Flows From Operating Activities** | | | | | | |
| Net Cash Provided by (Used in) Operating Activities | (225) | 245 | 9 | 7,519 | 24 | 7,572 |
| | | | | | | |
| **Cash Flows From Investing Activities** | | | | | | |
| Capital expenditures and investments | - | (3,064) | - | (8,386) | 1,400 | (10,050) |
| Working capital changes associated with investing activities | - | (4) | - | (964) | - | (968) |
| Proceeds from asset dispositions | 3,500 | 826 | - | 1,225 | (3,599) | 1,952 |
| Long-term advances/loans—related parties | - | (278) | - | (2,245) | 2,523 | - |
| Collection of advances/loans—related parties | - | - | - | 205 | (100) | 105 |
| Intercompany cash management | 102 | 46 | - | (148) | - | - |
| Other | - | 304 | - | 1 | 1 | 306 |
| Net Cash Provided by (Used in) Investing Activities | 3,602 | (2,170) | - | (10,312) | 225 | (8,655) |
| | | | | | | |
| **Cash Flows From Financing Activities** | | | | | | |
| Issuance of debt | - | 4,743 | - | 278 | (2,523) | 2,498 |
| Repayment of debt | - | (100) | - | (103) | 100 | (103) |
| Issuance of company common stock | 283 | - | - | (2) | (363) | (82) |
| Dividends paid | (3,664) | - | - | (339) | 339 | (3,664) |
| Other | 4 | (3,484) | - | 1,204 | 2,198 | (78) |
| Net Cash Provided by (Used in) Financing Activities | (3,377) | 1,159 | - | 1,038 | (249) | (1,429) |
| | | | | | | |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | - | - | (1) | (181) | - | (182) |
| | | | | | | |
| **Net Change in Cash and Cash Equivalents** | - | (766) | 8 | (1,936) | - | (2,694) |
| Cash and cash equivalents at beginning of period | - | 770 | 7 | 4,285 | - | 5,062 |
| Cash and Cash Equivalents at End of Period | $ - | 4 | 15 | 2,349 | - | 2,368 |

| Statement of Cash Flows | Year Ended December 31, 2014* | | | | | |
|---|---|---|---|---|---|---|
| **Cash Flows From Operating Activities** | | | | | | |
| Net cash provided by continuing operating activities | $ 17,259 | 2,948 | 27 | 16,941 | (20,763) | 16,412 |
| Net cash provided by discontinued operations | - | 202 | - | 408 | (453) | 157 |
| Net Cash Provided by Operating Activities | 17,259 | 3,150 | 27 | 17,349 | (21,216) | 16,569 |
| | | | | | | |
| **Cash Flows From Investing Activities** | | | | | | |
| Capital expenditures and investments | - | (6,507) | - | (14,840) | 4,262 | (17,085) |
| Working capital changes associated with investing activities | - | 17 | - | 163 | - | 180 |
| Proceeds from asset dispositions | 16,912 | 1,588 | - | 253 | (17,150) | 1,603 |
| Net sales of short-term investments | - | - | - | 253 | - | 253 |
| Long-term advances/loans—related parties | - | (736) | (241) | (7) | 984 | - |
| Collection of advances/loans—related parties | - | 593 | - | 112 | (102) | 603 |
| Intercompany cash management | (29,113) | 31,993 | - | (2,880) | - | - |
| Other | - | (415) | - | (31) | - | (446) |
| Net cash provided by (used in) continuing investing activities | (12,201) | 26,533 | (241) | (16,977) | (12,006) | (14,892) |
| Net cash provided by (used in) discontinued operations | - | 133 | - | (73) | (133) | (73) |
| Net Cash Provided by (Used in) Investing Activities | (12,201) | 26,666 | (241) | (17,050) | (12,139) | (14,965) |
| | | | | | | |
| **Cash Flows From Financing Activities** | | | | | | |
| Issuance of debt | - | 2,994 | - | 984 | (984) | 2,994 |
| Repayment of debt | (1,909) | (16) | - | (191) | 102 | (2,014) |
| Issuance of company common stock | 377 | - | - | - | (342) | 35 |
| Dividends paid | (3,525) | (17,588) | - | (3,768) | 21,356 | (3,525) |
| Other | (1) | (16,870) | - | 3,919 | 12,888 | (64) |
| Net cash provided by (used in) continuing financing activities | (5,058) | (31,480) | - | 944 | 33,020 | (2,574) |
| Net cash used in discontinued operations | - | - | - | (335) | 335 | - |
| Net Cash Provided by (Used in) Financing Activities | (5,058) | (31,480) | - | 609 | 33,355 | (2,574) |
| | | | | | | |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | - | - | (8) | (206) | - | (214) |
| | | | | | | |
| **Net Change in Cash and Cash Equivalents** | - | (1,664) | (222) | 702 | - | (1,184) |
| Cash and cash equivalents at beginning of period | - | 2,434 | 229 | 3,583 | - | 6,246 |
| Cash and Cash Equivalents at End of Period | $ - | 770 | 7 | 4,285 | - | 5,062 |

**Certain amounts have been reclassified to conform to current-period presentation. See Note 21—Cash Flow Information, in the Notes to the Consolidated Financial Statements.*

| Statement of Cash Flows | Millions of Dollars | | | | | | |
|---|---|---|---|---|---|---|---|
| | Year Ended December 31, 2013* | | | | | | |
| | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Australia Funding Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
| **Cash Flows From Operating Activities** | | | | | | | |
| Net cash provided by (used in) continuing operating activities | $ (295) | 22,928 | (2) | 1 | 14,510 | (21,286) | 15,856 |
| Net cash provided by discontinued operations | - | 91 | - | - | 642 | (448) | 285 |
| Net Cash Provided by (Used in) Operating Activities | (295) | 23,019 | (2) | 1 | 15,152 | (21,734) | 16,141 |
| **Cash Flows From Investing Activities** | | | | | | | |
| Capital expenditures and investments | - | (4,821) | - | - | (13,566) | 2,850 | (15,537) |
| Working capital changes associated with investing activities | - | 68 | - | - | (123) | - | (55) |
| Proceeds from asset dispositions | - | 2,633 | - | - | 9,745 | (2,158) | 10,220 |
| Net purchases of short-term investments | - | - | - | - | (263) | - | (263) |
| Long-term advances/loans—related parties | - | (342) | - | - | (545) | 887 | - |
| Collection of advances/loans—related parties | - | 174 | 750 | 169 | 3,010 | (3,958) | 145 |
| Intercompany cash management | 2,511 | (15,919) | - | - | 13,408 | - | - |
| Other | - | 21 | - | - | (233) | - | (212) |
| Net cash provided by (used in) continuing investing activities | 2,511 | (18,186) | 750 | 169 | 11,433 | (2,379) | (5,702) |
| Net cash used in discontinued operations | - | (52) | - | - | (603) | 52 | (603) |
| Net Cash Provided by (Used in) Investing Activities | 2,511 | (18,238) | 750 | 169 | 10,830 | (2,327) | (6,305) |
| **Cash Flows From Financing Activities** | | | | | | | |
| Issuance of debt | - | 522 | - | - | 365 | (887) | - |
| Repayment of debt | - | (2,924) | (750) | - | (1,230) | 3,958 | (946) |
| Change in restricted cash | 748 | - | - | - | - | - | 748 |
| Issuance of company common stock | 365 | - | - | - | - | (345) | 20 |
| Dividends paid | (3,334) | - | (4) | - | (21,984) | 21,988 | (3,334) |
| Other | 3 | 52 | - | - | (2,984) | (692) | (3,621) |
| Net cash used in continuing financing activities | (2,218) | (2,350) | (754) | - | (25,833) | 24,022 | (7,133) |
| Net cash used in discontinued operations | - | - | - | - | (39) | 39 | - |
| Net Cash Used in Financing Activities | (2,218) | (2,350) | (754) | - | (25,872) | 24,061 | (7,133) |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | - | (9) | - | - | (66) | - | (75) |
| **Net Change in Cash and Cash Equivalents** | (2) | 2,422 | (6) | 170 | 44 | - | 2,628 |
| Cash and cash equivalents at beginning of period | 2 | 12 | 6 | 59 | 3,539 | - | 3,618 |
| Cash and Cash Equivalents at End of Period | $ - | 2,434 | - | 229 | 3,583 | - | 6,246 |

**Certain amounts have been reclassified to conform to current-period presentation. See Note 21—Cash Flow Information, in the Notes to the Consolidated Financial Statements.*

## Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## Item 9A. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures designed to ensure information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the Act), is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of December 31, 2015, with the participation of our management, our Chairman and Chief Executive Officer (principal executive officer) and our Executive Vice President, Finance and Chief Financial Officer (principal financial officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Act, of ConocoPhillips' disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman and Chief Executive Officer and our Executive Vice President, Finance and Chief Financial Officer concluded our disclosure controls and procedures were operating effectively as of December 31, 2015.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

### Management's Annual Report on Internal Control Over Financial Reporting

This report is included in Item 8 on page 78 and is incorporated herein by reference.

### Report of Independent Registered Public Accounting Firm

This report is included in Item 8 on page 79 and is incorporated herein by reference.

## Item 9B. OTHER INFORMATION

None.

## PART III

### Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our executive officers appears in Part I of this report on pages 30 and 31.

**Code of Business Ethics and Conduct for Directors and Employees**

We have a Code of Business Ethics and Conduct for Directors and Employees (Code of Ethics), including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have posted a copy of our Code of Ethics on the "Corporate Governance" section of our internet website at *www.conocophillips.com* (within the Investors>Corporate Governance section). Any waivers of the Code of Ethics must be approved, in advance, by our full Board of Directors. Any amendments to, or waivers from, the Code of Ethics that apply to our executive officers and directors will be posted on the "Corporate Governance" section of our internet website.

All other information required by Item 10 of Part III will be included in our Proxy Statement relating to our 2016 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2016, and is incorporated herein by reference.*

### Item 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2016 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2016, and is incorporated herein by reference.*

### Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2016 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2016, and is incorporated herein by reference.*

### Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2016 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2016, and is incorporated herein by reference.*

### Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2016 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2016, and is incorporated herein by reference.*

**Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in our 2016 Proxy Statement are not deemed to be a part of this Annual Report on Form 10-K or deemed to be filed with the Commission as a part of this report.*

## PART IV

### Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements and Supplementary Data
The financial statements and supplementary information listed in the Index to Financial Statements, which appears on page 77, are filed as part of this annual report.

2. Financial Statement Schedules
Schedule II—Valuation and Qualifying Accounts, appears below. All other schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to consolidated financial statements.

3. Exhibits
The exhibits listed in the Index to Exhibits, which appears on pages 176 through 183, are filed as part of this annual report.

### SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS (Consolidated)

**ConocoPhillips**

| | Millions of Dollars | | | | |
|---|---|---|---|---|---|
| Description | Balance at January 1 | Charged to Expense | Other(a) | Deductions | Balance at December 31 |
| **2015** | | | | | |
| Deducted from asset accounts: | | | | | |
| Allowance for doubtful accounts and notes receivable | **$ 5** | **4** | **(2)** | **- (b)** | **7** |
| Deferred tax asset valuation allowance | **970** | **6** | **(21)** | **(221)** | **734** |
| Included in other liabilities: | | | | | |
| Restructuring accruals | **61** | **303** | **(8)** | **(200)(c)** | **156** |
| 2014 | | | | | |
| Deducted from asset accounts: | | | | | |
| Allowance for doubtful accounts and notes receivable | $ 8 | - | (2) | (1)(b) | 5 |
| Deferred tax asset valuation allowance | 969 | 127 | (26) | (100) | 970 |
| Included in other liabilities: | | | | | |
| Restructuring accruals | 19 | 71 | (6) | (23)(c) | 61 |
| 2013 | | | | | |
| Deducted from asset accounts: | | | | | |
| Allowance for doubtful accounts and notes receivable | $ 10 | - | - | (2)(b) | 8 |
| Deferred tax asset valuation allowance | 1,345 | (357) | 3 | (22) | 969 |
| Included in other liabilities: | | | | | |
| Restructuring accruals | 17 | 10 | (1) | (7)(c) | 19 |

*(a)Represents acquisitions/dispositions/revisions and the effect of translating foreign financial statements.*
*(b)Amounts charged off less recoveries of amounts previously charged off.*
*(c)Benefit payments.*

**CONOCOPHILLIPS**

**INDEX TO EXHIBITS**

| Exhibit Number | Description |
| --- | --- |
| 2.1 | Separation and Distribution Agreement Between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 3.1 | Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395). |
| 3.2 | Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987). |
| 3.3 | Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of December 6, 2013 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed December 10, 2013; File No. 001-32395). |
| 3.4 | Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of October 9, 2015 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on October 13, 2015; File No. 001-32395). |
| | ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request. |
| 10.1 | 1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.2 | 1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.3 | Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.4 | Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 001-00720). |
| 10.5 | Amendment and Restatement of ConocoPhillips Supplemental Executive Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.14 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |

| Exhibit Number | Description |
| --- | --- |
| 10.6 | Non-Employee Director Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.18 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.7 | Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.19 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.8 | Key Employee Missed Credited Service Retirement Plan of ConocoPhillips (incorporated by reference to Exhibit 10.10 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395). |
| 10.9 | Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.10.1 | Amendment and Restatement of ConocoPhillips Key Employee Supplemental Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.13 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.10.2* | First Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan, dated July 20, 2015. |
| 10.11.1 | Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips—Title I, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.11.2 | Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.11.3 | First Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated October 11, 2012 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395). |
| 10.11.4* | Second Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated December 17, 2015. |
| 10.12 | 2002 Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.13 | Amendment and Restatement of 1998 Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.14 | Amendment and Restatement of 1998 Key Employee Stock Performance Plan of ConocoPhillips (incorporated by reference to Exhibit 10.28 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.15 | Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips (incorporated by reference to Exhibit 10.17 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.16 | ConocoPhillips Form Indemnity Agreement with Directors (incorporated by reference to Exhibit 10.34 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.17.1 | Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of the Annual Report of ConocoPhillips Holding Company on Form 10-K for the year ended December 31, 1999; File No. 001-14521). |
| 10.17.2 | Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.17.3* | Phillips Petroleum Company Grantor Trust Agreement, dated June 1, 1998. |
| 10.17.4* | First Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated May 3, 1999. |
| 10.17.5* | Second Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated January 15, 2002. |
| 10.17.6* | Third Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated October 5, 2006. |
| 10.17.7* | Fourth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 1, 2012. |
| 10.17.8* | Fifth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 20, 2015. |
| 10.18.1 | ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10.40 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987). |
| 10.18.2 | First and Second Amendments to the ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395). |
| 10.19 | ConocoPhillips Matching Gift Plan for Directors and Executives (incorporated by reference to Exhibit 10.41 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987). |
| 10.20.1 | Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title I, dated April 19, 2012 (incorporated by reference to Exhibit 10.12.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.20.2 | Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, dated April 19, 2012 (incorporated by reference to Exhibit 10.12.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.20.3 | First Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips—Title II (incorporated by reference to Exhibit 10.20.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.20.4 | Second Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips—Title II (incorporated by reference to Exhibit 10.20.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395). |
| 10.20.5 | Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, 2013 Restatement dated November 17, 2014 (Amended and Restated effective as of January 1, 2013) (incorporated by reference to Exhibit 10.20.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2014; File No. 001-32395). |
| 10.21 | Amendment and Restatement of ConocoPhillips Key Employee Change in Control Severance Plan, effective January 1, 2014 (incorporated by reference to Exhibit 10.21 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2013; File No. 001-32395). |
| 10.22 | ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395). |
| 10.23.1 | 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix C of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2004 Annual Meeting of Shareholders; File No. 000-49987). |
| 10.23.2 | Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395). |
| 10.23.3 | Form of Performance Share Unit Award Agreement under the Performance Share Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395). |
| 10.24 | Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007 (incorporated by reference to Exhibit 10.30 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2007; File No. 001-32395). |
| 10.25 | 2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2009 Annual Meeting of Shareholders; File No. 001-32395). |
| 10.26.1 | 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2011 Annual Meeting of Shareholders; File No. 001-32395). |
| 10.26.2 | Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective February 9, 2012 (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2012; File No. 001-32395). |
| 10.26.3 | Form of Restricted Stock Units Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective April 4, 2012 (incorporated by reference to Exhibit 10.6 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.26.4 | Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective May 8, 2012 (incorporated by reference to Exhibit 10.7 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.26.5 | Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 18, 2012 (incorporated by reference to Exhibit 10.26.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.6 | Form of Performance Share Unit Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.6 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.7 | Form of Performance Share Unit Agreement—Canada under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.8 | Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.8 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.9 | Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.9 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.10 | Form of Make-up Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated January 1, 2012 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2013; File No. 001-32395). |
| 10.26.11 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.12* | Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016. |
| 10.26.13 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Restricted Stock Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.14* | Form of Key Employee Award Agreement, as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016. |

| Exhibit Number | Description |
|---|---|
| 10.26.15 | Form of Performance Period IX Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.16 | Form of Performance Period IX Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.4 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.17 | Form of Performance Period X Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.5 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.18 | Form of Performance Period X Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.6 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.19 | Form of Performance Period XI Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.7 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.20 | Form of Performance Period XI Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.8 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.21 | Form of Performance Period XII Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.22 | Form of Performance Period XII Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.23* | Form of Performance Period XIV Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016. |

| Exhibit Number | Description |
| --- | --- |
| 10.26.24* | Form of Performance Period XIV Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016. |
| 10.26.25 | Form of Inducement Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated March 31, 2014 (incorporated by reference to Exhibit 10.11 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.27.1 | 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 14, 2014; File No. 001-32395). |
| 10.27.2 | Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program of ConocoPhillips, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 15, 2014 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2014; File No. 001-32395). |
| 10.27.3 | Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 3, 2015 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2015; File No. 001-32395). |
| 10.27.4 | Form of Retention Award Terms and Conditions, as part of the Restricted Stock Unit Award, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2015; File No. 001-32395). |
| 10.28 | Amendment and Restatement of Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips, dated April 19, 2012 (incorporated by reference to Exhibit 10.8 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.29 | Amendment, Change of Sponsorship, and Restatement of Certain Nonqualified Deferred Compensation Plans of ConocoPhillips, dated April 19, 2012 (incorporated by reference to Exhibit 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.30 | Amendment and Restatement of the Burlington Resources Inc. Management Supplemental Benefits Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.31 | Indemnification and Release Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.32 | Intellectual Property Assignment and License Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.2 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |

| Exhibit Number | Description |
| --- | --- |
| 10.33 | Tax Sharing Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.3 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.34 | Employee Matters Agreement between ConocoPhillips and Phillips 66, dated April 12, 2012 (incorporated by reference to Exhibit 10.4 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.35 | Transition Services Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.5 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.36 | ConocoPhillips Clawback Policy dated October 3, 2012 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395). |
| 12* | Computation of Ratio of Earnings to Fixed Charges. |
| 21* | List of Subsidiaries of ConocoPhillips. |
| 23.1* | Consent of Ernst & Young LLP. |
| 23.2* | Consent of DeGolyer and MacNaughton. |
| 31.1* | Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934. |
| 31.2* | Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934. |
| 32* | Certifications pursuant to 18 U.S.C. Section 1350. |
| 99* | Report of DeGolyer and MacNaughton. |
| 101.INS* | XBRL Instance Document. |
| 101.SCH* | XBRL Schema Document. |
| 101.CAL* | XBRL Calculation Linkbase Document. |
| 101.DEF* | XBRL Definition Linkbase Document. |
| 101.LAB* | XBRL Labels Linkbase Document. |
| 101.PRE* | XBRL Presentation Linkbase Document. |

* Filed herewith.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

**CONOCOPHILLIPS**

February 23, 2016

*/s/ Ryan M. Lance*
Ryan M. Lance
Chairman of the Board of Directors
and Chief Executive Officer

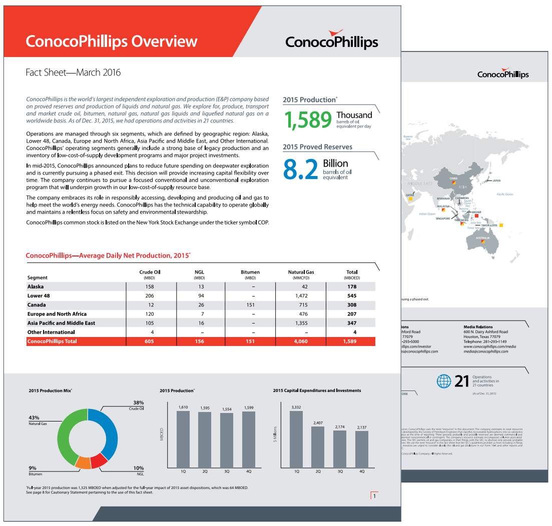
Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 23, 2016, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

| **Signature** | **Title** |
|---|---|
| */s/ Ryan M. Lance*<br>Ryan M. Lance | Chairman of the Board of Directors<br>and Chief Executive Officer<br>(Principal executive officer) |
| */s/ Jeff W. Sheets*<br>Jeff W. Sheets | Executive Vice President, Finance<br>and Chief Financial Officer<br>(Principal financial officer) |
| */s/ Glenda M. Schwarz*<br>Glenda M. Schwarz | Vice President and Controller<br>(Principal accounting officer) |

| | |
|---|---|
| */s/ Richard L. Armitage*<br>Richard L. Armitage | Director |
| */s/ Richard H. Auchinleck*<br>Richard H. Auchinleck | Director |
| */s/ Charles E. Bunch*<br>Charles E. Bunch | Director |
| */s/ James E. Copeland, Jr.*<br>James E. Copeland, Jr. | Director |
| */s/ Gay Huey Evans*<br>Gay Huey Evans | Director |
| */s/ John V. Faraci*<br>*John V. Faraci* | Director |
| */s/ Jody Freeman*<br>Jody Freeman | Director |
| */s/ Arjun N. Murti*<br>Arjun N. Murti | Director |
| */s/ Robert A. Niblock*<br>Robert A. Niblock | Director |
| */s/ Harald J. Norvik*<br>Harald J. Norvik | Director |

ConocoPhillips

# Explore ConocoPhillips




## Fact Sheets

The ConocoPhillips fact sheets provide detailed operational updates for each of the company's six segments. The fact sheets are updated annually and are available at *www.conocophillips.com/factsheets*.


## Sustainability Report

The ConocoPhillips Sustainability Report provides an overview of the company's sustainable development programs and metrics. The 2015 Sustainability Report will be available in June at *www.conocophillips.com/sustainability*.

## Learn more at www.conocophillips.com

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Certain disclosures in this annual report may be considered "forward-looking" statements. These are made pursuant to "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The "Cautionary Statement" in the Management's Discussion and Analysis in ConocoPhillips' 2015 Form 10-K should be read in conjunction with such statements.

"ConocoPhillips," "the company," "we," "us" and "our" are used interchangeably in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries.

Definition of "resources": ConocoPhillips uses the term "resources" in this document. The company estimates its total resources based on a system developed by the Society of Petroleum Engineers that classifies recoverable hydrocarbons into six categories based on their status at the time of reporting. Three (proved, probable and possible reserves) are deemed commercial, and three others are deemed noncommercial or contingent. The company's resource estimate encompasses volumes associated with all six categories. The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves. We use the terms "resource" and "resources" in this annual report, which the SEC's guidelines prohibit us from including in filings with the SEC. U.S. investors are urged to consider closely the oil and gas disclosures in our Form 10-K and other reports and filings with the SEC.


FSC www.fsc.org MIX Paper from responsible sources FSC® C101537

ConocoPhillips

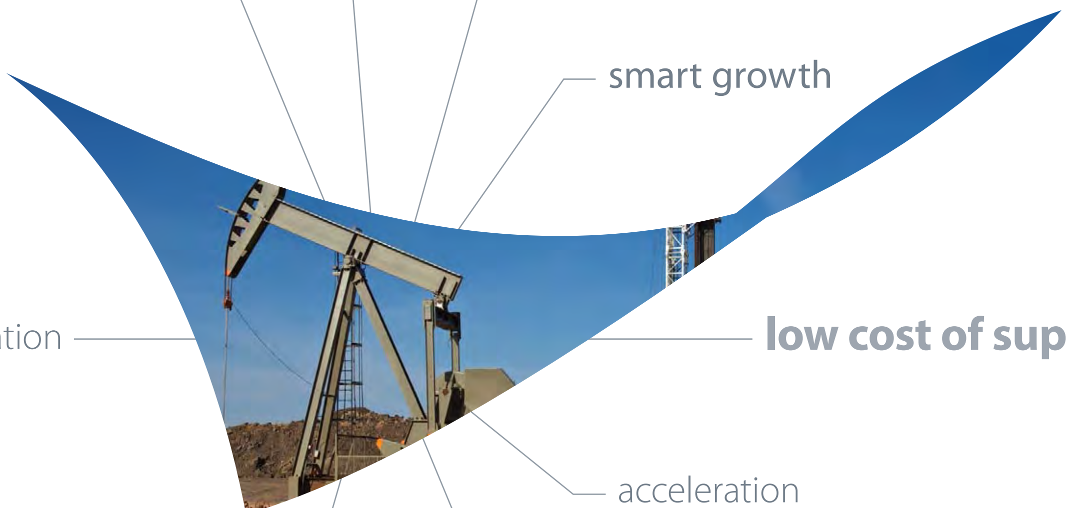
ConocoPhillips

low breakeven price

SPIRIT Values

transformation

smart growth



differentiation

low cost of supply

acceleration

superior returns

flexibility

# 2016 Annual Report

# Letter to Shareholders

Dear Fellow Shareholders:

This year's letter to shareholders picks up where last year's left off. At that time, Brent oil prices had fallen below $30 per barrel, and the impacts of the significant price downturn that began in 2014 were intensifying across the industry. Our company was continuing to take actions to reset our business based on our view that prices are likely to be lower and more volatile in the future. This was a fundamental mindset shift — from one that set plans based on expected oil and natural gas prices to one that embraced uncertainty.

Not long ago, oil prices were high and relatively stable. But we believe that world has changed. The strength of a company won't necessarily lie in its ability to survive this change, but in its ability to adapt. We must position our company to deliver predictable performance through the cycles by maintaining a strong balance sheet, a low cost structure and a low cost of supply resource base, while preserving strategic flexibility. And that's exactly what we've done.

Since 2014, we've lowered our capital expenditures by more than 70 percent and significantly reduced our operating costs. We exited higher-cost areas of business, shifted our capital to shorter-cycle investments and reduced our dividend. These changes were difficult, but allowed us to sustainably lower the Brent price at which we can fund our capital program and dividend with cash from operating activities. We also continued streamlining our portfolio, generating more than $3 billion of proceeds from non-core asset sales during the past two years.

With these actions behind us, we announced an updated value proposition at our Analyst and Investor Meeting in November 2016. I started that meeting with a question: can an E&P company deliver value through price cycles with a disciplined, returns-based value proposition? Our answer? Yes. We then laid out a strategy and plan that reflect the breadth of our transformation, while offering a bold alternative to many E&P company business models that still focus on absolute growth. We'll manage the business for cash flow generation with five clear cash flow allocation priorities. In order, these priorities are: invest enough cash to maintain flat production and pay our existing dividend; grow our dividend; reduce our debt levels to target an 'A' credit rating; pay out roughly 20 to 30 percent of our cash from operating activities to shareholders through a combination of the dividend and share buybacks; and grow production.

It's early days since we launched our updated value proposition, but so far, the reception has been positive. Importantly, by early 2017, all five priorities had been activated. We delivered against all of them, including growing production by 3 percent in 2016, when adjusted for the impact of dispositions and downtime.

Clearly, 2016 was a year of intense change. However, through it all, our operational performance didn't falter. This is a credit to our workforce. They delivered strong safety performance, while exceeding operational targets across the business. We achieved first LNG at our APLNG Train 2 megaproject in Australia, as well as project startups in Canada, China, Europe and Malaysia. The past two years tested the organization, but our workforce showed resilience and commitment every step of the way.

We can never declare victory in this business. There is always work to do. But we have a viable strategy, with a sound operating plan in place. Our workforce is focused on safely executing that plan. We're excited about our future because we believe we're leading the industry in offering a compelling approach to a cyclical business that is ripe for sustainable change.

I would like to thank our shareholders, workforce and board of directors for their support. We'll continue working hard every day to maintain that support.

Ryan M. Lance

**Ryan M. Lance**
Chairman and Chief Executive Officer
Feb. 21, 2017

# 2016

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

# Form 10-K

(Mark One)

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2016**

OR

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

For the transition period from ____________________ to ____________________

Commission file number: **001-32395**

# ConocoPhillips

*(Exact name of registrant as specified in its charter)*

| | |
|---|---|
| **Delaware** | **01-0562944** |
| *(State or other jurisdiction of incorporation or organization)* | *(I.R.S. Employer Identification No.)* |

**600 North Dairy Ashford**
**Houston, TX 77079**
*(Address of principal executive offices) (Zip Code)*

Registrant's telephone number, including area code: **281-293-1000**

Securities registered pursuant to Section 12(b) of the Act:

| Title of each class | Name of each exchange on which registered |
|---|---|
| Common Stock, $.01 Par Value | New York Stock Exchange |
| 6.65% Debentures due July 15, 2018 | New York Stock Exchange |
| 7% Debentures due 2029 | New York Stock Exchange |

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. [x] Yes [ ] No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. [ ] Yes [x] No

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). [x] Yes [ ] No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

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

Large accelerated filer [x] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

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

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2016, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $43.60, was $54.0 billion.

The registrant had 1,235,832,469 shares of common stock outstanding at January 31, 2017.

**Documents incorporated by reference:**
Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 16, 2017 (Part III)

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# PART I

Unless otherwise indicated, "the company," "we," "our," "us" and "ConocoPhillips" are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Items 1 and 2—Business and Properties, contain forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. 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 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 the heading "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 72.

## Items 1 and 2. BUSINESS AND PROPERTIES

## CORPORATE STRUCTURE

ConocoPhillips is the world's largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. ConocoPhillips was incorporated in the state of Delaware on November 16, 2001, in connection with, and in anticipation of, the merger between Conoco Inc. and Phillips Petroleum Company. The merger between Conoco and Phillips was consummated on August 30, 2002.

In April 2012, the ConocoPhillips Board of Directors approved the separation of our downstream business into an independent, publicly traded energy company, Phillips 66. Each ConocoPhillips stockholder received one share of Phillips 66 stock for every two shares of ConocoPhillips stock held at the close of business on the record date of April 16, 2012. The separation was completed on April 30, 2012, and activities related to Phillips 66 have been treated as discontinued operations for all periods prior to the separation.

In 2012, we agreed to sell our interest in the North Caspian Sea Production Sharing Agreement (Kashagan) and our Nigeria and Algeria businesses (collectively, the "Disposition Group"). We sold our Nigeria business in the third quarter of 2014, and we sold Kashagan and our Algeria business in the fourth quarter of 2013. Results for the Disposition Group have been reported as discontinued operations in the applicable periods presented. For additional information on the sale of our Nigeria business, see Note 3—Discontinued Operations, in the Notes to Consolidated Financial Statements.

Headquartered in Houston, Texas, we have operations and activities in 17 countries. Our key focus areas include safely operating producing assets, executing major developments and exploring for new resources in promising areas. Our portfolio includes resource-rich North American tight oil and oil sands assets; lower-risk conventional assets in North America, Europe, Asia and Australia; several liquefied natural gas (LNG) developments; and an inventory of global conventional and unconventional exploration prospects.

At December 31, 2016, ConocoPhillips employed approximately 13,300 people worldwide.

In November 2016, we announced our planned $5 billion to $8 billion asset disposition program, primarily associated with North American natural gas assets, over the next two years. For additional information on asset sales, see the "Outlook" section of Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

## SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic information, see Note 24—Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2016, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

The information listed below appears in the "Oil and Gas Operations" disclosures following the Notes to Consolidated Financial Statements and is incorporated herein by reference:

- Proved worldwide crude oil, natural gas liquids, natural gas and bitumen reserves.
- Net production of crude oil, natural gas liquids, natural gas and bitumen.
- Average sales prices of crude oil, natural gas liquids, natural gas and bitumen.
- Average production costs per barrel of oil equivalent (BOE).
- Net wells completed, wells in progress and productive wells.
- Developed and undeveloped acreage.

The following table is a summary of the proved reserves information included in the "Oil and Gas Operations" disclosures following the Notes to Consolidated Financial Statements. Approximately 81 percent of our proved reserves are located in politically stable countries that belong to the Organization for Economic Cooperation and Development. Natural gas reserves are converted to BOE based on a 6:1 ratio: six thousand cubic feet (MCF) of natural gas converts to one BOE. See Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance the understanding of the following summary reserves table.

| | Millions of Barrels of Oil Equivalent | | |
|---|---|---|---|
| **Net Proved Reserves at December 31** | **2016** | 2015 | 2014 |
| Crude oil | | | |
| Consolidated operations | **2,047** | 2,270 | 2,605 |
| Equity affiliates | **88** | 93 | 103 |
| Total Crude Oil | **2,135** | 2,363 | 2,708 |
| Natural gas liquids | | | |
| Consolidated operations | **457** | 508 | 662 |
| Equity affiliates | **47** | 50 | 53 |
| Total Natural Gas Liquids | **504** | 558 | 715 |
| Natural gas | | | |
| Consolidated operations | **1,807** | 1,988 | 2,543 |
| Equity affiliates | **730** | 878 | 874 |
| Total Natural Gas | **2,537** | 2,866 | 3,417 |
| Bitumen | | | |
| Consolidated operations | **159** | 687 | 598 |
| Equity affiliates | **1,089** | 1,706 | 1,468 |
| Total Bitumen | **1,248** | 2,393 | 2,066 |
| Total consolidated operations | **4,470** | 5,453 | 6,408 |
| Total equity affiliates | **1,954** | 2,727 | 2,498 |
| Total company | **6,424** | 8,180 | 8,906 |

Total production, including Libya, of 1,569 thousand barrels of oil equivalent per day (MBOED) decreased 1 percent in 2016 compared with 2015. The decrease in total average production primarily resulted from normal field decline and the loss of 72 MBOED mainly attributable to the 2015 dispositions of several non-core assets in the Lower 48, western Canada and the sale of our interest in the Polar Lights Company in Russia. The decrease in production was partly offset by additional production from major developments, including tight oil plays in the Lower 48; APLNG in Australia; the Western North Slope in Alaska; the Kebabangan gas field in Malaysia; and the Greater Ekofisk Area in Norway. Improved drilling and well performance in Canada, Norway, the Lower 48, and China, as well as lower unplanned downtime in the Lower 48 also partly offset the decrease in production. Assets sold in 2016 produced 27 MBOED and 36 MBOED in 2016 and 2015, respectively.

Our worldwide annual average realized price was $28.35 per BOE in 2016, a decrease of 17 percent compared with $34.34 per BOE in 2015, which reflected lower average realized prices across all commodities. Our worldwide annual average crude oil price decreased 15 percent in 2016, from $48.26 per barrel in 2015 to $40.86 per barrel in 2016. Additionally, our worldwide annual average natural gas liquids prices decreased 6 percent, from $17.79 per barrel in 2015 to $16.68 per barrel in 2016. Our worldwide annual average natural gas price decreased 24 percent, from $3.96 per MCF in 2015 to $3.00 per MCF in 2016. Average annual bitumen prices also decreased 18 percent, from $18.72 per barrel in 2015 to $15.27 per barrel in 2016.

ALASKA

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids, natural gas and LNG. We are the largest crude oil producer in Alaska and have major ownership interests in two of North America's largest oil fields located on Alaska's North Slope: Prudhoe Bay and Kuparuk. We also have a significant operating interest in the Alpine Field, located on the Western North Slope. Additionally, we are one of Alaska's largest owners of state, federal and fee exploration leases, with approximately 0.5 million net undeveloped acres at year-end 2016. Following the impairment of our Chukchi Sea leases in the fourth quarter of 2015, we surrendered 0.3 million acres in the Chukchi Sea in May 2016. In 2016, Alaska operations contributed 19 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

| | | | 2016 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD* | Natural Gas MMCFD** | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Greater Prudhoe Area | 36.1% | BP | 88 | 9 | 90 |
| Greater Kuparuk Area | 52.2–55.5 | ConocoPhillips | 50 | - | 50 |
| Western North Slope | 78.0 | ConocoPhillips | 37 | 1 | 37 |
| Cook Inlet Area | 33.3-100.0 | ConocoPhillips | - | 15 | 2 |
| Total Alaska | | | 175 | 25 | 179 |

**Thousands of barrels per day.*
***Millions of cubic feet per day.*

<u>*Greater Prudhoe Area*</u>
The Greater Prudhoe Area includes the Prudhoe Bay Field and five satellite fields, as well as the Greater Point McIntyre Area fields. Prudhoe Bay, the largest oil field on Alaska's North Slope, is the site of a large waterflood and enhanced oil recovery operation, as well as a gas plant which processes natural gas to recover natural gas liquids before reinjection into the reservoir. Prudhoe Bay's satellites are Aurora, Borealis, Polaris, Midnight Sun and Orion, while the Point McIntyre, Niakuk, Raven, Lisburne and North Prudhoe Bay State fields are part of the Greater Point McIntyre Area.

<u>*Greater Kuparuk Area*</u>
We operate the Greater Kuparuk Area, which consists of the Kuparuk Field and four satellite fields: Tarn, Tabasco, Meltwater and West Sak. Kuparuk is located 40 miles west of Prudhoe Bay. Field installations include three central production facilities which separate oil, natural gas and water, as well as a separate seawater treatment plant. Development drilling at Kuparuk consists of rotary-drilled wells and horizontal multi-laterals from existing well bores utilizing coiled-tubing drilling.

Drill Site 2S, in the southwestern area of the Kuparuk Field, was sanctioned in October 2014. First oil was achieved in October 2015, and completion of the first phase of the project was achieved in 2016.

The 1H Northeast West Sak (NEWS) oil development targeting the West Sak reservoir in the Kuparuk River Unit, was sanctioned in March 2015. First production is anticipated in 2018.

<u>*Western North Slope*</u>
On the Western North Slope, we operate the Colville River Unit, which includes the Alpine Field and three satellite fields: Nanuq, Fiord and Qannik. Alpine is located 34 miles west of Kuparuk. In October 2015, first oil was achieved at Alpine West CD5, a new drill site which extends the Alpine reservoir west into the National Petroleum Reserve-Alaska (NPR-A). During the year, we approved drilling an additional 18 wells, bringing CD5 up to its full permit capacity.

The Greater Mooses Tooth Unit, the first unit established entirely within the NPR-A, was formed in 2008. In 2017, we began construction in the unit, which is currently planned to have two drill sites; Greater Mooses Tooth #1 and #2, with expected first oil in 2018 and 2020, respectively.

*Cook Inlet Area*
We have a 100 percent interest and are the operator of the Kenai LNG Facility in the Cook Inlet Area. The Kenai LNG Facility includes a 1.6 million-tons-per-year capacity plant, as well as docking and loading facilities for LNG tankers. LNG from the plant has historically been transported and sold to utility companies in Japan. In February 2016, our export license was renewed for an additional two years. However, there was no LNG export program in 2016 due to market conditions. We are currently marketing this facility.

In April and October 2016, we sold our interests in the Beluga River Unit natural gas field and the North Cook Inlet Unit, respectively, both in the Cook Inlet Area. The full-year 2016 production from the assets sold was 2 MBOED.

*Point Thomson*
We own a 4.9 percent interest in the Point Thomson Unit, which is located approximately 60 miles east of Prudhoe Bay. An Initial Production System (IPS) was brought online in April 2016, and achieved full production of 400 BOED net of condensate in December.

*Alaska North Slope Gas*
In 2016, we, along with affiliates of Exxon Mobil Corporation, BP p.l.c. and Alaska Gasline Development Corporation (AGDC), a state-owned corporation (collectively, the “AKLNG co-venturers”), completed preliminary front-end engineering and design (pre-FEED) technical work for a potential LNG project which would liquefy and export natural gas from Alaska’s North Slope and deliver it to market. In September 2016, we, along with the affiliates of ExxonMobil and BP, indicated our intention not to progress into the next phase of the project due to changes in the economic environment. Given AGDC’s intention to continue efforts to advance a North Slope Gas project, the AKLNG co-venturers executed certain agreements to enhance AGDC’s ability to do so. We remain supportive of AGDC’s efforts to progress a project.

*Exploration*
In 2016, we drilled three exploration wells in the NPR-A. Two of these wells, Tinmiaq 2 and 6, form the Willow discovery, which is located in the northeast portion of the NPR-A. The third exploration well was recorded to dry hole expense in the fourth quarter of 2016. Appraisal of the Willow discovery commenced in January 2017 with the acquisition of 3-D seismic. In a follow-up to the Willow discovery, we were successful in December’s state and federal lease sales on the Western North Slope, where we were the high bidder on 139 tracts for a total of 737,252 gross acres.

*Transportation*
We transport the petroleum liquids produced on the North Slope to south central Alaska through an 800-mile pipeline that is part of Trans-Alaska Pipeline System (TAPS). We have a 29.1 percent ownership interest in TAPS, and we also have ownership interests in the Alpine, Kuparuk and Oliktok pipelines on the North Slope.

Our wholly-owned subsidiary, Polar Tankers, Inc., manages the marine transportation of our North Slope production, using five company-owned, double-hulled tankers, and charters third-party vessels as necessary. The tankers deliver oil from Valdez, Alaska, primarily to refineries on the west coast of the United States.

## LOWER 48

The Lower 48 segment consists of operations located in the U.S. Lower 48 states and the Gulf of Mexico. The Lower 48 business is organized within three regions covering the Gulf Coast, Mid-Continent and Rockies. As a result of tight oil opportunities, we have directed our investments toward certain shorter cycle time, low cost-of-supply plays. In July 2015, we announced our plan to reduce future deepwater exploration spending. We have subsequently terminated our Gulf of Mexico deepwater drillship contracts. We hold 12.4 million net onshore and offshore acres in the Lower 48. In 2016, the Lower 48 contributed 30 percent of our worldwide liquids production and 32 percent of our natural gas production.

| | | | 2016 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Eagle Ford | Various% | Various | 129 | 193 | 161 |
| Gulf of Mexico | Various | Various | 15 | 13 | 17 |
| Gulf Coast—Other | Various | Various | 5 | 18 | 8 |
| Total Gulf Coast | | | 149 | 224 | 186 |
| Permian | Various | Various | 42 | 130 | 64 |
| Barnett | Various | Various | 5 | 36 | 11 |
| Anadarko Basin | Various | Various | 5 | 102 | 22 |
| Total Mid-Continent | | | 52 | 268 | 97 |
| Bakken | Various | Various | 53 | 50 | 61 |
| Wyoming/Uinta | Various | Various | - | 89 | 15 |
| Niobrara | Various | Various | 2 | 4 | 3 |
| San Juan | Various | Various | 27 | 584 | 124 |
| Total Rockies | | | 82 | 727 | 203 |
| Total U.S. Lower 48 | | | 283 | 1,219 | 486 |

*Onshore*
We hold 12.3 million net acres of onshore conventional and unconventional acreage in the Lower 48, the majority of which is either held by production or owned by the company. Our unconventional holdings total approximately 2.6 million net acres in the following areas:

- 900,000 net acres in the San Juan Basin, located in northwestern New Mexico and southwestern Colorado.
- 620,000 net acres in the Bakken, located in North Dakota and eastern Montana.
- 213,000 net acres in the Eagle Ford, located in South Texas.
- 104,000 net acres in the Niobrara, located in northeastern Colorado.
- 123,500 net acres in the Permian, located in West Texas and southeastern New Mexico.
- 68,000 net acres in the Barnett, located in north central Texas.
- 591,000 net acres in other unconventional exploration plays.

The majority of our 2016 onshore production originated from the Eagle Ford, San Juan, Permian and Bakken. Onshore activities in 2016 were centered mostly on continued development of emerging and existing assets, with an emphasis on areas with low cost of supply, particularly in growing unconventional plays. The 2016 drilling activity levels declined relative to 2015 due to reduced capital spending in the low commodity price environment. Our major focus areas in 2016 included the following:

- Eagle Ford—The Eagle Ford scaled down full-field development in 2016. We operated three rigs on average in 2016, resulting in 69 operated wells drilled and 80 operated wells brought online. Production decreased 7 percent in 2016 compared with 2015, and reached a net peak of 176 MBOED, compared with 190 MBOED in 2015.
- Bakken—We operated two rigs on average throughout the year in the Bakken. We continued our pad drilling efficiency, drilling 34 operated wells during the year and bringing 37 operated wells online. We achieved net peak production of 72 MBOED in 2016, compared with 80 MBOED in 2015.
- San Juan Basin—The San Juan Basin includes significant conventional gas production, which yields approximately 20 percent natural gas liquids, as well as the majority of our U.S. coalbed methane (CBM) production. We hold approximately 1.3 million net acres of oil and gas leases by production in San Juan, including approximately 900,000 net unconventional acres of lease rights.
- Permian Basin—The Permian Basin is an area where we are leveraging our conventional legacy position by utilizing new technology to improve the ultimate recovery and value from these fields. This technology should also identify new, unconventional plays across the region. We hold approximately 1.0 million net acres in the Permian, which includes 123,500 net unconventional acres. The Permian Basin produced 64 MBOED in 2016, which includes 15 MBOED of unconventional production.

In 2015, we completed the sale of certain non-core assets in East Texas and North Louisiana and South Texas. Production from the assets sold was 33 MBOED, approximately 6 percent of the total Lower 48 segment production in 2015. In the second quarter of 2016, we completed the sale of certain non-core assets in the Delaware basin. The full-year 2016 production from the assets sold was 1 MBOED.

*Gulf of Mexico*
At year-end 2016, our portfolio of producing properties in the Gulf of Mexico primarily consisted of one operated field and three fields operated by co-venturers, including:

- 75 percent operated working interest in the Magnolia Field in Garden Banks Blocks 783 and 784.
- 15.9 percent nonoperated working interest in the unitized Ursa Field located in the Mississippi Canyon Area.
- 15.9 percent nonoperated working interest in the Princess Field, a northern subsalt extension of the Ursa Field.
- 12.4 percent nonoperated working interest in the unitized K2 Field, comprised of seven blocks in the Green Canyon Area.

*Exploration*

- *Conventional Exploration*
  At December 31, 2016, we held approximately 73,000 net acres in the deepwater Gulf of Mexico.

  We own a 30 percent nonoperated working interest in the Shenandoah discovery, which was announced in 2009, and had a net book value of $286 million at December 31, 2016. Appraisal drilling continued in 2016 with the fifth Shenandoah well reaching total depth in the third quarter. In February 2017, the sixth Shenandoah well, Shenandoah WR52-3, reached total depth. Drilling of a sidetrack well from Shenandoah WR52-3 also commenced in February.

As part of our continued phased exit from deepwater exploration, in 2016, we decided not to pursue further development of the nonoperated Gibson and Tiber wells, collectively known as the Tigris project. Accordingly, we recorded dry hole expenses for previously suspended Gibson and Tiber wells, and impairment charges for the applicable leaseholds.

We recorded dry hole and associated leasehold impairment expense in the first quarter of 2016 for the Melmar exploration well.

- *Unconventional Exploration*
  In 2016, we drilled a total of five operated unconventional wells, primarily in the Eagle Ford. Our onshore focus areas include the Permian in the Delaware Basin and the Niobrara in the Denver-Julesburg Basin, as well as several emerging plays. We continue to assess and appraise these and other unconventional opportunities.

**Facilities**

*Freeport LNG Terminal*

In July 2013, we agreed with Freeport LNG Development, L.P. to terminate our long-term agreement to use 0.9 billion cubic feet per day of regasification capacity at Freeport's 1.5 billion cubic-feet-per-day LNG receiving terminal in Quintana, Texas. The termination agreement conditions were satisfied in 2014. Our terminal regasification capacity was reduced to zero on July 1, 2016. For additional information, see Note 7—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

*Golden Pass LNG Terminal*

We have a 12.4 percent ownership interest in the Golden Pass LNG Terminal and affiliated Golden Pass Pipeline, with a combined net book value of approximately $260 million at December 31, 2016. It is located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal became commercially operational in May 2011. We hold terminal and pipeline capacity for the receipt, storage and regasification of the LNG purchased from Qatar Liquefied Gas Company Limited (3) (QG3) and the transportation of regasified LNG to interconnect with major interstate natural gas pipelines. Utilization of the terminal has been and is expected to be limited, as market conditions currently favor the flow of LNG to European and Asian markets. As a result, we are evaluating opportunities to optimize the value of the terminal facilities.

*Greater Northern Iron Ore Properties Trust*

We held the reversionary interest in the Greater Northern Iron Ore Properties trust (the Trust), a grantor trust that owns mineral and surface interests in the Mesabi Iron Range in northeastern Minnesota and certain other personal property. Pursuant to the terms of the Trust Agreement, the Trust terminated on April 6, 2015. On November 3, 2016, the end of the wind-down period, documents memorializing our ownership of certain Trust property, including all the Trust's mineral properties and active leases, were delivered to us. The $144 million fair value of the Trust's net assets transferred to us and a gain of $88 million were both recorded in the fourth quarter of 2016. On December 8, 2016, we closed on a sale of the Trust's and certain other assets for net proceeds of $148 million. For additional information, see Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

*Other*

- San Juan Gas Plant—We operate and own a 50 percent interest in the San Juan Gas Plant, a 550 million cubic-feet-per-day capacity natural gas processing plant in Bloomfield, New Mexico.
- Lost Cabin Gas Plant—We operate and own a 46 percent interest in the Lost Cabin Gas Plant, a 312 million cubic-feet-per-day capacity natural gas processing facility in Lysite, Wyoming.
- Helena Condensate Processing Facility—We operate and own the Helena Condensate Processing Facility, a 90,000 barrel-per-day condensate processing plant located in Kenedy, Texas.

- Sugarloaf Condensate Processing Facility—We operate and own an 87.5 percent interest in the Sugarloaf Condensate Processing Facility, a 30,000 barrel-per-day condensate processing plant located near Pawnee, Texas.
- Bordovsky Condensate Processing Facility—We operate and own the Bordovsky Condensate Processing Facility, a 15,000 barrel-per-day condensate processing plant located in Kenedy, Texas.

## CANADA

Our Canadian operations mainly consist of natural gas fields in western Canada and oil sands developments in the Athabasca Region of northeastern Alberta. In 2016, operations in Canada contributed 23 percent of our worldwide liquids production and 14 percent of our natural gas production.

| | | | 2016 | | | |
|---|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Bitumen MBD | Total MBOED |
| **Average Daily Net Production** | | | | | | |
| Western Canada | Various% | Various | 30 | 524 | - | 117 |
| Surmont | 50.0 | ConocoPhillips | - | - | 35 | 35 |
| Foster Creek | 50.0 | Cenovus | - | - | 70 | 70 |
| Christina Lake | 50.0 | Cenovus | - | - | 78 | 78 |
| Total Canada | | | 30 | 524 | 183 | 300 |

*Western Canada*
Our operations in western Canada extend across Alberta and British Columbia. We operate or have ownership interests in approximately 30 natural gas processing plants in the region, and, as of December 31, 2016, held leasehold rights in 3.1 million net acres in western Canada. Our investments in 2016 were focused mainly on opportunities in the following three core development areas:

- Deep Basin—We hold leasehold rights in 1.3 million net acres in the Deep Basin, located in northwest Alberta and northeast British Columbia. In 2016, Deep Basin achieved average net production of 46 MBOED, and we drilled eight horizontal wells.
- Kaybob-Edson—We hold leasehold rights in 0.7 million net acres in the Kaybob-Edson Area, located south of the Deep Basin in west central Alberta. Net production for Kaybob-Edson averaged 37 MBOED in 2016, and we drilled 15 horizontal wells.
- Clearwater—We hold leasehold rights in 0.8 million net acres in the Clearwater area, located in west central Alberta, south of Kaybob-Edson. In 2016, average net production for Clearwater was 34 MBOED.

*Oil Sands*
Our bitumen resources in Canada are produced via an enhanced thermal oil recovery method called steam-assisted gravity drainage (SAGD), whereby steam is injected into the reservoir, effectively liquefying the heavy bitumen, which is recovered and pumped to the surface for further processing. We hold approximately 0.9 million net acres of land in the Athabasca Region of northeastern Alberta.

- Surmont—The Surmont oil sands leases are located approximately 35 miles south of Fort McMurray, Alberta. Surmont is a 50/50 joint venture with Total S.A. The Surmont 2 project achieved first production in 2015, and production continued to ramp up in 2016. Net production at Surmont increased 21 MBOED in 2016.

- FCCL—FCCL Partnership, a Canadian upstream general partnership, is a 50/50 business venture with Cenovus Energy Inc. FCCL's assets are operated by Cenovus and include the Foster Creek, Christina Lake and Narrows Lake SAGD bitumen developments. FCCL continues to progress development plans for each of these assets.

    - *Foster Creek*
      Foster Creek is located approximately 200 miles northeast of Edmonton, Alberta. With the achievement of first production at Phase G in 2016, there are seven producing phases at Foster Creek, Phases A through G. Net production at Foster Creek increased approximately 5 MBOED in 2016.

    - *Christina Lake*
      Christina Lake is located approximately 75 miles south of Fort McMurray, Alberta. Christina Lake Phase F achieved first production in 2016. There are now six producing phases at Christina Lake. Construction on Phase G, which has a design capacity of 50 MBOED gross, will resume in 2017 after being deferred since 2014. First production from Phase G is expected in the second half of 2019. Net production at Christina Lake increased approximately 6 MBOED in 2016.

    - *Narrows Lake*
      Narrows Lake Phase A, was sanctioned in late 2012 and is expected to have 45 MBOED of gross design production capacity. Construction has been deferred, however, we expect to progress engineering activity in 2017.

*Exploration*
We hold exploration acreage in four areas of Canada: onshore western Canada, offshore eastern Canada, the Mackenzie Delta/Beaufort Sea Region and the Arctic Islands. Our primary exploration focus is on unconventional plays in western Canada.

- *Conventional Exploration*
  During 2014, we entered into a farm-in agreement to acquire a 30 percent nonoperated interest in six exploration licenses covering approximately five million gross acres in the deepwater Shelburne Basin, offshore Nova Scotia. In 2016, we recorded dry hole expenses associated with two wells in the Shelburne Basin, and an impairment charge for the undeveloped leasehold costs. Other related costs have been accrued.

  In August 2016, we sold our Newfoundland Partnership, which held a 30 percent nonoperated interest in the exploration license in the Flemish Pass Basin, offshore Newfoundland.

- *Unconventional Exploration*
  We hold approximately 0.7 million net acres in the emerging Montney, Muskwa, Duvernay and Canol unconventional plays in Alberta, northeastern British Columbia and the Northwest Territories. During 2016, we completed a lease swap for unproved lands in the Blueberry area and continued to drill exploration and appraisal wells in the Montney play, which extends from British Columbia into Alberta. Full-year 2016 production from the assets swapped was 5 MBOED. For additional information, see Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

EUROPE AND NORTH AFRICA

The Europe and North Africa segment consists of operations and exploration activities in Norway, the United Kingdom and Libya. In 2016, operations in Europe and North Africa contributed 14 percent of our worldwide liquids production and 12 percent of natural gas production.

**Norway**

| | | | 2016 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Greater Ekofisk Area | 35.1% | ConocoPhillips | 54 | 48 | 62 |
| Alvheim | 20.0 | Aker BP | 11 | 10 | 13 |
| Heidrun | 24.0 | Statoil | 15 | 15 | 17 |
| Other | Various | Statoil | 16 | 81 | 29 |
| Total Norway | | | 96 | 154 | 121 |

The Greater Ekofisk Area is located approximately 200 miles offshore Stavanger, Norway, in the North Sea, and comprises three producing fields: Ekofisk, Eldfisk and Embla. Crude oil is exported to Teesside, England, and the natural gas is exported to Emden, Germany. Ekofisk South achieved first production in 2013, while Eldfisk II achieved startup in January 2015. Continued development drilling in the Greater Ekofisk Area will contribute additional production over the coming years, as additional wells come online.

The Alvheim development is located in the northern part of the North Sea and consists of a floating production, storage and offloading (FPSO) vessel and subsea installations. Produced crude oil is exported via shuttle tankers, and natural gas is transported to the Scottish Area Gas Evacuation (SAGE) terminal at St. Fergus, Scotland, through the SAGE pipeline.

The Heidrun Field is located in the Norwegian Sea. Produced crude oil is stored in a floating storage unit and exported via shuttle tankers. Part of the natural gas is currently injected into the reservoir for optimization of crude oil production, some gas is exported to the Continent via gas processing terminals in Norway, while the remainder is exported for use as feedstock in a methanol plant in Norway, in which we own an 18 percent interest.

We also have varying ownership interests in five other producing fields in the Norway sector of the North Sea and in the Norwegian Sea, as well as the Aasta Hansteen development. The operator is targeting first gas for Aasta Hansteen by late 2018.

*Exploration*
We participated in two nonoperated exploration wells in the Oseberg and Alvheim areas. Both wells were discoveries and are currently undergoing evaluation. We were awarded three licenses in 2016, including the PL845 and PL782SB, both with interests of 40 percent, and PL859, which has a 15 percent interest.

*Transportation*
We own a 35.1 percent interest in the Norpipe Oil Pipeline System, a 220-mile pipeline which carries crude oil from Ekofisk to a crude oil stabilization and natural gas liquids processing facility in Teesside, England.

**United Kingdom**

| | | | 2016 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Britannia | 58.7% | ConocoPhillips | 4 | 77 | 17 |
| Britannia Satellites | 26.3–83.5* | ConocoPhillips | 12 | 72 | 24 |
| J-Area | 32.5–36.5 | ConocoPhillips | 10 | 60 | 20 |
| Southern North Sea | Various | ConocoPhillips | - | 49 | 8 |
| East Irish Sea | 100.0 | HRL | - | 42 | 7 |
| Other | Various | Various | 5 | 5 | 6 |
| Total United Kingdom | | | 31 | 305 | 82 |

**Includes the Chevron-operated Alder field, ConocoPhillips equity 26.3%.*

Britannia is one of the largest natural gas and condensate fields in the North Sea. We assumed operatorship of Britannia in August 2015, following the acquisition of third party equity in Britannia Operator Limited, which is now wholly owned by ConocoPhillips. Condensate is delivered through the Forties Pipeline to an oil stabilization and processing plant near the Grangemouth Refinery in Scotland, while natural gas is transported through Britannia's line to St. Fergus, Scotland. The Britannia satellite fields, Callanish, Brodgar, Enochdhu and Alder, produce via subsea manifolds and pipelines linked to the Britannia platform. Project startups for the Brodgar H3 susbsea well, and Enochdhu, a single well tie back to Callanish, were achieved in 2015. First gas was achieved from Alder, a single well tie back to Britannia, in the fourth quarter of 2016.

The J-Area consists of the Judy/Joanne, Jade and Jasmine fields, located in the U.K. Central North Sea. The Jasmine Field is a high-pressure, high-temperature gas condensate reservoir located approximately six miles west of the Judy Platform. The development includes a 24-slot wellhead platform with a bridge-linked accommodation and utilities platform, a six-mile, 16-inch multi-phase pipeline bundle, and a riser and processing platform bridge-linked to the existing Judy Platform.

We have various ownership interests in several producing gas fields in the Rotliegendes and Carboniferous areas of the Southern North Sea. Decommissioning activity in the Southern North Sea is ongoing, with final production from the Viking transportation system and associated satellites achieved in early 2016. Our interests in the East Irish Sea include the Millom, Dalton and Calder fields, which are operated on our behalf by a third party.

We own a 24 percent interest in the Clair Field, located in the Atlantic Margin. Clair Ridge is the second phase of development for the Clair Field and is comprised of a 36-slot drilling and production facility with a bridge-linked accommodation and utilities platform. The new facilities will tie into existing oil and gas export pipelines to the Shetland Islands. Initial production for Clair Ridge is targeted for 2018.

*Exploration*
In 2016, we recorded dry hole expense for the fully-owned Temple Wood well in the Greater Britannia Area, which was permanently plugged and abandoned.

*Transportation*
We operate the Teesside oil and Theddlethorpe gas terminals in which we have 29.3 percent and 50 percent ownership interests, respectively. We also have a 100 percent ownership interest in the Rivers Gas Terminal, operated by a third party.

**Greenland**
*Exploration*
In the first quarter of 2016, we completed the process to assign our participating interest in the nonoperated Avinngaq license. Additionally, our operated Qamut license expired on December 31, 2016. Our work program in Greenland is complete, pending certain approvals.

**Libya**

| | | | 2016 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Waha Concession | 16.3 % | Waha Oil Co. | 2 | 1 | 2 |
| Total Libya | | | 2 | 1 | 2 |

The Waha Concession consists of multiple concessions and encompasses nearly 13 million gross acres in the Sirte Basin. Our production operations in Libya and related oil exports were interrupted in mid-2013, as a result of the shutdown of the Es Sider crude oil export terminal at the end of July 2013. The Es Sider Terminal briefly reopened in the third quarter of 2014 and production and liftings resumed temporarily; however, further disruptions occurred in December 2014, and production was shut in again. Production resumed in Libya in October 2016, with three crude liftings from Es Sider in January 2017. We expect a gradual ramp-up in activity.

ASIA PACIFIC AND MIDDLE EAST

The Asia Pacific and Middle East segment has exploration and production operations in China, Indonesia, Malaysia and Australia; producing operations in Qatar and Timor-Leste; and exploration activities in Brunei. In 2016, operations in the Asia Pacific and Middle East segment contributed 14 percent of our worldwide liquids production and 42 percent of natural gas production.

**Australia and Timor Sea**

| | | | 2016 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Australia Pacific LNG | 37.5% | ConocoPhillips/ Origin Energy | - | 531 | 89 |
| Bayu-Undan | 56.9 | ConocoPhillips | 13 | 254 | 55 |
| Athena/Perseus | 50.0 | ExxonMobil | - | 35 | 6 |
| Total Australia and Timor Sea | | | 13 | 820 | 150 |

*Australia Pacific LNG*
Australia Pacific LNG Pty Ltd (APLNG), our joint venture with Origin Energy Limited and China Petrochemical Corporation (Sinopec), is focused on producing CBM from the Bowen and Surat basins in Queensland, Australia, and converting the coalbed methane into LNG. Natural gas is sold to domestic customers, while LNG is exported. Origin operates APLNG's upstream production and pipeline system, and we operate the downstream LNG facility, located on Curtis Island near Gladstone, Queensland, as well as the LNG export sales business.

Two fully subscribed 4.5 million tonnes-per-year LNG trains have been completed. Approximately 3,900 net wells are ultimately envisioned to supply both the domestic gas market and the LNG sales contracts. The wells are supported by gathering systems, central gas processing and compression stations, water treatment facilities, and an export pipeline connecting the gas fields to the LNG facilities. The first APLNG Train 1 cargo sailed in January 2016, and LNG sales continued throughout the year. Train 1 LNG is being sold to Sinopec under a 20-year sales agreement for up to 4.3 million metric tonnes of LNG per year. APLNG Train 2 achieved first production in the third quarter of 2016. The LNG from Train 2 is being sold to Sinopec under a 20-year sales agreement for an additional 3.3 million metric tonnes of LNG per year through 2035, and Japan-based Kansai Electric Power Co., Inc. under a 20-year sales agreement for approximately 1 million metric tonnes of LNG per year.

APLNG has an $8.5 billion project finance facility, of which $8.5 billion had been drawn from the facility at December 31, 2016. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility until the project achieves financial completion. In October 2016, we reached financial completion for Train 1, which reduced our associated guarantee by 60 percent. For additional information, see Note 4—Variable Interest Entities (VIEs), Note 7—Investments, Loans and Long-Term Receivables, and Note 12—Guarantees, in the Notes to Consolidated Financial Statements.

*Bayu-Undan*

The Bayu-Undan gas condensate field is located in the Timor Sea Joint Petroleum Development Area between Timor-Leste and Australia. We also operate and own a 56.9 percent interest in the associated Darwin LNG Facility, located at Wickham Point, Darwin.

The Bayu-Undan natural gas recycle facility processes wet gas; separates, stores and offloads condensate, propane and butane; and re-injects dry gas back into the reservoir. In addition, a 310-mile natural gas pipeline connects the facility to the 3.5 million tonnes-per-year capacity Darwin LNG Facility. Produced natural gas is piped to the Darwin LNG Plant, where it is converted into LNG before being transported to international markets. In 2016, we sold 168 billion gross cubic feet of LNG primarily to utility customers in Japan.

The Bayu-Undan Phase Three Development consists of two standalone, subsea horizontal wells tied back to the existing drilling, production and processing platform. The first subsea horizontal well was tied back to the existing drilling, production and processing platform, and commenced production in 2015, while the second well was suspended due to insufficient deliverability to the platform. A continuation of the Bayu-Undan Phase Three Development is being evaluated with the front-end engineering and design phase approaching completion. The current premise is that drilling of one subsea and two platform wells will commence in 2018, pending internal, joint venture and regulatory approval.

ConocoPhillips served a Notice of Arbitration on the Timor-Leste Minister of Finance in October 2012 for outstanding disputes related to a series of tax assessments. The arbitration hearing was conducted in Singapore in June 2014 under the United Nations Commission on International Trade Laws (UNCITRAL) arbitration rules, pursuant to the terms of the Tax Stability Agreement with the Timor-Leste government. We reached a settlement with the Timor-Leste government on these disputes in 2016.

*Athena/Perseus*

The Athena production license (WA-17-L) is located offshore Western Australia and contains part of the Perseus Field, which straddles the boundary with WA-1-L, an adjoining license area. Natural gas is produced from these licenses.

*Greater Sunrise*

We have a 30 percent interest in the Greater Sunrise gas and condensate field located in the Timor Sea. In April 2016, the Timor-Leste Government initiated conciliation under the United Nations Convention of the Law of the Sea (UNCLOS) in an attempt to negotiate permanent maritime boundaries. The conciliation is on-going between the governments of Timor-Leste and Australia.

The UNCLOS conciliation does not directly impact our underlying interests in Sunrise; however, we and the Sunrise co-venturers are unable to commit to further commercial and technical work activities due to the uncertainty created by the lack of government alignment. Accordingly, current activities are restricted to compliance and social investment, as well as maintaining relationships and development options for Sunrise.

*Exploration*

- *Conventional Exploration*
  We operate three exploration permits in the Browse Basin, offshore northwest Australia, in which we own a 40 percent interest in permits WA-315-P, WA-398-P and TP 28, of the Greater Poseidon Area. The TP 28 Western Australia State exploration permit was granted for five years from January 2017, with a 40 percent working interest and was excised from the existing permits as agreed between state and federal regulators. Phase I of the Browse Basin drilling campaign in 2009/2010 resulted in three discoveries in the Greater Poseidon Area: Poseidon-1, Poseidon-2 and Kronos-1. Phase II of the drilling campaign resulted in five additional discoveries: Boreas-1, Zephyros-1, Proteus-1 SD2, Poseidon-North-1 and Pharos-1. All wells have been completed, plugged and abandoned.

  We operate two retention leases in the Bonaparte Basin, offshore northern Australia, where we own a 37.5 percent interest in leases NT/RL5 and NT/RL6, containing the Barossa and Caldita discoveries. A new 3-D seismic survey was completed over the Barossa and Caldita Field area between August and October 2016. Drilling of the next appraisal well, Barossa-5, commenced in January 2017. Drilling of a subsequent well, Barossa-6, may follow dependent on the results of Barossa-5.

**Indonesia**

| | | | 2016 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| South Natuna Sea Block B | 40.0 % | ConocoPhillips | 8 | 65 | 19 |
| South Sumatra | 45.0–54.0 | ConocoPhillips | 2 | 328 | 57 |
| Total Indonesia | | | 10 | 393 | 76 |

We operate three production sharing contracts (PSCs) in Indonesia: The Corridor Block and South Jambi "B," both located in South Sumatra, and Kualakurun in Central Kalimantan. Currently there is production from the Corridor Block. In 2016, we sold our 40 percent working interest in the offshore South Natuna Sea Block B PSC, which had 3 producing oil fields, and 16 natural gas fields in various stages of development. Full-year 2016 production from South Natuna Sea Block B was 19 MBOED.

*South Sumatra*
The Corridor PSC consists of five oil fields and seven natural gas fields in various stages of development. Natural gas is supplied from the Grissik and Suban gas processing plants to the Duri steamflood in central Sumatra and to markets in Singapore, Batam and West Java. Production from the South Jambi "B" PSC has reached depletion and field development has been suspended.

*Exploration*
During 2016, we relinquished our 80 percent interest in the Warim Block PSC. We have a 60 percent working interest in the Kualakurun PSC, located in Central Kalimantan, which was signed in May 2015. This block has an area of approximately 2 million gross acres.

*Transportation*
We are a 35 percent owner of a consortium company that has a 40 percent ownership in PT Transportasi Gas Indonesia, which owns and operates the Grissik to Duri and Grissik to Singapore natural gas pipelines.

**China**

| | Interest | Operator | 2016 Liquids MBD | Natural Gas MMCFD | Total MBOED |
|---|---|---|---|---|---|
| **Average Daily Net Production** | | | | | |
| Penglai | 49.0 % | CNOOC | 32 | 1 | 32 |
| Panyu | 24.5 | CNOOC | 9 | - | 9 |
| Total China | | | 41 | 1 | 41 |

The Penglai 19-3, 19-9 and 25-6 fields are located in Bohai Bay Block 11/05. Production from the Phase 1 development of the Penglai 19-3 Field began in 2002. Phase 2 included six additional wellhead platforms and an FPSO vessel, and was fully operational by 2009.

As part of further development of the Penglai 19-9 Field, a new wellhead platform, which adds up to 62 wells, is progressing according to schedule, with two wells completed and brought online in December 2016.

We sanctioned the Penglai 19-3/19-9 Phase 3 Project in December 2015. This project will consist of three new wellhead platforms and a central processing platform. First oil from Phase 3 is expected in 2018.

The Panyu development, located in Block 15/34 in the South China Sea, is comprised of three oil fields: Panyu 4-2, Panyu 5-1 and Panyu 11-6. The production period for Panyu 4-2 and 5-1 will expire in 2018, and the production period for Panyu 11-6 will expire in 2022.

*Exploration*

In 2016, we participated in a successful appraisal well in the Penglai fields, which will support future development plans.

**Malaysia**

| | Interest | Operator | 2016 Liquids MBD | Natural Gas MMCFD | Total MBOED |
|---|---|---|---|---|---|
| **Average Daily Net Production** | | | | | |
| Siakap North-Petai | 21.0 % | Murphy | 3 | 2 | 3 |
| Gumusut | 29.0 | Shell | 36 | - | 36 |
| KBB | 30.0 | KPOC | 1 | 45 | 9 |
| Total Malaysia | | | 40 | 47 | 48 |

We own interests in six PSCs in Malaysia. Three are located off the eastern Malaysian state of Sabah: Block G, Block J and the Kebabangan Cluster (KBBC). Three other blocks, deepwater Block 3E, Block SK313 and Block WL4-00 are located off the eastern Malaysian state of Sarawak.

*Block G*
We have a 21 percent interest in the unitized Siakap North-Petai oil field, which began producing in the first quarter of 2014 and reached its estimated net annual peak production of 5 MBOED in 2015.

First production from Malikai was achieved in December 2016, with estimated net annual peak production of 18 MBOED expected in 2019. The Limbayong-1 well was drilled in 2002 and resulted in a gas discovery. The Limbayong-2 appraisal well was drilled in 2013 and resulted in an oil discovery. Development options are being evaluated. We own a 35 percent interest in the Malikai, Limbayong and Pisagan discoveries.

*Block J*
First production for Gumusut occurred from an early production system in 2012. Production from a permanent, semi-submersible floating production vessel was achieved in October 2014, with net annual peak production of 36 MBOED reached in 2016. Unitization of the Gumusut Field with Brunei was recorded in 2014 and reduced our ownership interest from 33 percent to an initial 29 percent. A final ownership split is expected to be agreed in 2017. Gumusut Phase 2 infill drilling is planned to start in 2018.

*KBBC*
We own a 30 percent interest in the KBBC PSC. Development of the KBB gas field commenced in 2011, and first production was achieved in November 2014. Estimated net annual peak production of 26 MBOED is expected in 2018. Development options for the Kamunsu East gas field are being evaluated.

*Exploration*
We own a 50 percent operated interest in deepwater Block 3E, which encompasses approximately 480,000 gross acres offshore Sarawak. Seismic processing was completed in 2015. The Langsat-1 exploration well was spud in February 2017.

In the fourth quarter of 2016, we entered into a farm-in agreement to acquire a 50 percent interest in Block SK 313, a 1.4 million gross-acre exploration block, effective January 2017. Following completion of the Sadok-1 exploration well in January 2017, we assumed operatorship of the block from PETRONAS.

We were awarded Block WL4-00, which encompasses approximately 629,000 gross acres, in January 2017. We have a 50 percent operated interest in this block which includes the Salam-1 oil discovery. A new 3-D seismic survey is planned for 2017 with drilling of an appraisal well expected in 2018.

**Brunei**
*Exploration*
We have a 6.25 percent working interest in the deepwater Block CA-2 PSC, which has an exploration period through December 2018. Exploration has been ongoing since September 2011, with natural gas discovered at the Kelidang NE-1 and Keratau-1 wells in 2013 and at the Keratau SW-1 well in 2015. Evaluation of the results is ongoing.

**Myanmar**
*Exploration*
In 2014, we were awarded deepwater Block AD-10 in the 2013 Myanmar offshore oil and gas bidding round. We signed the PSC in the second quarter of 2015. In 2016, we assigned our participating interest to the operator.

**Qatar**

| | Interest | Operator | 2016 Liquids MBD | 2016 Natural Gas MMCFD | 2016 Total MBOED |
|---|---|---|---|---|---|
| **Average Daily Net Production** | | | | | |
| QG3 | 30.0 % | Qatargas Operating Company Limited | 22 | 368 | 84 |
| Total Qatar | | | 22 | 368 | 84 |

QG3 is an integrated development jointly owned by Qatar Petroleum (68.5 percent), ConocoPhillips (30 percent) and Mitsui & Co., Ltd. (1.5 percent). QG3 consists of upstream natural gas production facilities, which produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar's North Field over a 25 year life, in addition to a 7.8 million gross tonnes-per-year LNG facility. LNG is shipped in leased LNG carriers destined for sale globally.

QG3 executed the development of the onshore and offshore assets as a single integrated development with Qatargas 4 (QG4), a joint venture between Qatar Petroleum and Royal Dutch Shell plc. This included the joint development of offshore facilities situated in a common offshore block in the North Field, as well as the construction of two identical LNG process trains and associated gas treating facilities for both the QG3 and QG4 joint ventures. Production from the LNG trains and associated facilities is combined and shared.

OTHER INTERNATIONAL

The Other International segment includes exploration activities in Colombia and Chile. In 2016, we sold ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal.

**Angola**
*Exploration*
Our 50 percent operated interest in Block 36 and our 30 percent operated interest in Block 37, both of which are located in Angola's subsalt play trend, expired on December 31, 2016. In February 2017, we reached a settlement agreement on our contract for the Athena drilling rig, initially secured for our four-well commitment program in Angola. As a result of the cancellation, we will recognize a before-tax charge of $43 million net in the first quarter of 2017.

**Senegal**
*Exploration*
On October 28, 2016, we sold ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal. See Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements, for information regarding our asset dispositions.

**Colombia**
*Unconventional Exploration*
We have an 80 percent operated interest in the Middle Magdalena Basin Block VMM-3. The block extends over approximately 67,000 net acres and contains the Picoplata-1 well, which completed drilling in 2015. Production tests and appraisal of the area are ongoing.

We hold 70 percent nonoperated interests in the deep rights in the Santa Isabel Block in the Middle Magdalena Basin, which covers approximately 71,000 net acres. The relinquishment of the Santa Isabel Block was accepted and the parties are in the process of documenting such relinquishment.

The exploration and production contract for the VMM27 Block, in the Middle Magdalena Basin, where we held a 30 percent nonoperated interest, has been fully terminated. We also hold a 30 percent nonoperated interest in the VMM28 Block, in the Middle Magdalena Basin, where we are in the process of terminating with the relevant parties and the regulatory agency.

**Chile**

*Exploration*

In June 2016, we entered into an agreement with Empresa Nacional Del Petroleo (ENAP) to acquire an additional 44 percent participating interest in the onshore Coiron Block located in the Magallanes Basin in southern Chile where we already had 5 percent participation. Assignment of the additional participating interest to ConocoPhillips was approved by the Chilean Ministry of Energy and the Controller General of Chile. ENAP holds the remaining 51 percent participating interest and will continue to be the operator.

In 2016, two exploration wells were successfully drilled, logged and cored. In 2017, we will continue to explore and appraise the Coiron Block.

**Venezuela**

In October 2014, we filed for arbitration under the rules of the International Chamber of Commerce (ICC) against Petroleos de Venezuela (PDVSA), the Venezuela state oil company, for contractual compensation related to the Petrozuata and Hamaca heavy crude oil projects. The ICC arbitration is a separate and independent legal action from the investment treaty arbitration against the government of Venezuela, which is currently proceeding before an arbitral tribunal under the World Bank's International Centre for Settlement for Investment Disputes (ICSID). The ICSID Tribunal is determining the damages owed to ConocoPhillips as a result of Venezuela's unlawful expropriation of ConocoPhillips' significant oil investments in the Petrozuata and Hamaca heavy crude oil projects and the offshore Corocoro development project in June 2007. In October 2016, ConocoPhillips brought fraudulent transfer actions in the U.S. District Court of Delaware against PDVSA, alleging that PDVSA has taken actions to improperly expatriate assets from the United States to Venezuela in an effort to avoid judgment creditors. For additional information, see Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

**Ecuador**

In December 2012, an ICSID Tribunal issued a decision on liability in favor of Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, finding that Ecuador's seizure of Blocks 7 and 21 was an unlawful expropriation in violation of the Ecuador-U.S. Bilateral Investment Treaty. In February 2017, the tribunal unanimously awarded Burlington $380 million for Ecuador's unlawful expropriation and breach of the U.S.-Ecuador bilateral investment treaty. The tribunal also issued a separate decision finding Ecuador to be entitled to $42 million for limited environmental and infrastructure impacts associated with the operations of Burlington and its co-venturer. Ecuador recently filed a request for annulment of this decision with ICSID. The schedule for the annulment process has not yet been set. For additional information, see Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

**Discontinued Operations**

See Note 3—Discontinued Operations, in the Notes to Consolidated Financial Statements, for information regarding our discontinued operations.

OTHER

**Marketing Activities**

Our Commercial organization manages our worldwide commodity portfolio, which mainly includes natural gas, crude oil, bitumen, natural gas liquids and LNG. Marketing activities are performed through offices in the United States, Canada, Europe and Asia. In marketing our production, we attempt to minimize flow disruptions, maximize realized prices and manage credit-risk exposure. Commodity sales are generally made at prevailing market prices at the time of sale. We also purchase and sell third-party volumes to better position the company to satisfy customer demand while fully utilizing transportation and storage capacity.

*Natural Gas*
Our natural gas production, along with third-party purchased gas, is primarily marketed in the United States, Canada, Europe and Asia. Our natural gas is sold to a diverse client portfolio which includes local distribution companies; gas and power utilities; large industrials; independent, integrated or state-owned oil and gas companies; as well as marketing companies. To reduce our market exposure and credit risk, we also transport natural gas via firm and interruptible transportation agreements to major market hubs.

*Crude Oil, Bitumen and Natural Gas Liquids*
Our crude oil, bitumen and natural gas liquids revenues are derived from production in the United States, Canada, Australia, Asia, Africa and Europe. These commodities are primarily sold under contracts with prices based on market indices, adjusted for location, quality and transportation.

*LNG*
LNG marketing efforts are focused on equity LNG production facilities located in Australia and Qatar. LNG is primarily sold under long-term contracts with prices based on market indices.

**Energy Partnerships**
*Marine Well Containment Company*
We are a founding member of the Marine Well Containment Company (MWCC), a non-profit organization formed in 2010, which provides well containment equipment and technology in the deepwater U.S. Gulf of Mexico. MWCC's containment system meets the U.S. Bureau of Safety and Environmental Enforcement requirements for a subsea well containment system that can respond to a deepwater well control incident in the U.S. Gulf of Mexico. For additional information, see Note 4—Variable Interest Entities (VIEs), in the Notes to Consolidated Financial Statements.

*Subsea Well Response Project*
In 2011, we, along with several leading oil and gas companies, launched the Subsea Well Response Project (SWRP), a non-profit organization based in Stavanger, Norway, which was created to enhance the industry's capability to respond to international subsea well control incidents. Through collaboration with Oil Spill Response Limited, a non-profit organization in the United Kingdom, subsea well intervention equipment is available for the industry to use in the event of a subsea well incident. This complements the work being undertaken in the United States by MWCC.

*Oil Spill Response Removal Organizations (OSROs)*
We maintain memberships in several OSROs across the globe as a key element of our preparedness program in addition to internal response resources. Many of the OSROs are not-for-profit cooperatives owned by the member companies wherein we may actively participate as a member of the board of directors, steering committee, work group or other supporting role. Globally, our primary OSRO is Oil Spill Response Ltd. based in the U.K., with facilities in several other countries and the ability to respond anywhere in the world. In North America, our primary OSROs include the Marine Spill Response Corporation for the continental U.S. and Alaska Clean Seas and Ship Escort/Response Vessel System for the Alaska North Slope and Prince William Sound, respectively. Internationally, we maintain memberships in various regional OSROs including the Norwegian Clean Seas Association for Operating Companies, Australian Marine Oil Spill Center and Petroleum Industry of Malaysia Mutual Aid Group.

**Technology**
We have several technology programs that improve our ability to develop unconventional reservoirs, produce heavy oil economically with fewer emissions, improve the efficiency of our company's exploration program, increase recoveries from our legacy fields, and implement sustainability measures.

Our Optimized Cascade® LNG liquefaction technology business continues to be successful with the demand for new LNG plants. The technology has been licensed for use in 25 LNG trains around the world, with feasibility studies ongoing for additional trains.

## RESERVES

We have not filed any information with any other federal authority or agency with respect to our estimated total proved reserves at December 31, 2016. No difference exists between our estimated total proved reserves for year-end 2015 and year-end 2014, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2016.

## DELIVERY COMMITMENTS

We sell crude oil and natural gas from our producing operations under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Our Commercial organization also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be the spot market or a combination of our reserves and the spot market. Worldwide, we are contractually committed to deliver approximately 2.0 trillion cubic feet of natural gas, including approximately 363 billion cubic feet related to the noncontrolling interests of consolidated subsidiaries, and 180 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2027. We expect to fulfill the majority of these delivery commitments with proved developed reserves. In addition, we anticipate using proved undeveloped reserves and spot market purchases to fulfill any remaining commitments. See the disclosure on "Proved Undeveloped Reserves" in the "Oil and Gas Operations" section following the Notes to Consolidated Financial Statements, for information on the development of proved undeveloped reserves.

## COMPETITION

We compete with private, public and state-owned companies in all facets of the E&P business. Some of our competitors are larger and have greater resources. Each of our segments is highly competitive, with no single competitor, or small group of competitors, dominating.

We compete with numerous other companies in the industry, including state-owned companies, to locate and obtain new sources of supply and to produce oil, bitumen, natural gas liquids and natural gas in an efficient, cost-effective manner. Based on statistics published in the September 5, 2016, issue of the *Oil and Gas Journal*, we were the third-largest U.S.-based oil and gas company in worldwide liquids and natural gas production and reserves in 2015. We deliver our production into the worldwide commodity markets. Principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; economic analysis in connection with portfolio management; and safely operating oil and gas producing properties.

## GENERAL

At the end of 2016, we held a total of 714 active patents in 49 countries worldwide, including 286 active U.S. patents. During 2016, we received 37 patents in the United States and 66 foreign patents. Our products and processes generated licensing revenues of $128 million in 2016. The overall profitability of any business segment is not dependent on any single patent, trademark, license, franchise or concession.

Company-sponsored research and development activities charged against earnings were $116 million, $222 million and $263 million in 2016, 2015 and 2014, respectively.

*Health, Safety and Environment*

Our Health, Safety and Environment (HSE) organization provides tools and support to our business units and staff groups to help them ensure world class health, safety and environmental performance. The framework through which we safely manage our operations, the HSE Management System Standard, emphasizes process safety, risk management, emergency preparedness and environmental performance, with an intense focus on process and occupational safety. In support of the goal of zero incidents, HSE milestones and criteria are established annually to drive strong safety performance. Progress toward these milestones and criteria are measured and reported. HSE audits are conducted on business functions periodically, and improvement actions are established and tracked to completion. We also have detailed processes in place to address sustainable development in our economic, environmental and social performance. Our processes, related tools and requirements focus on water, biodiversity and climate change, as well as social and stakeholder issues.

The environmental information contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 63 through 66 under the captions "Environmental" and "Climate Change" is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2016 and those expected for 2017 and 2018.

**Website Access to SEC Reports**

Our internet website address is *www.conocophillips.com*. Information contained on our internet website is not part of this report on Form 10-K.

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on our website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the U.S. Securities and Exchange Commission (SEC). Alternatively, you may access these reports at the SEC's website at *www.sec.gov*.

## Item 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this Annual Report on Form 10-K. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

***Our operating results, our future rate of growth and the carrying value of our assets are exposed to the effects of changing commodity prices.***

Prices for crude oil, bitumen, natural gas, natural gas liquids and LNG can fluctuate widely. Globally, prices for crude oil, bitumen, natural gas, natural gas liquids and LNG have experienced significant declines from their historic levels during 2013 and 2014, with excess of supply relative to global demand leading to global inventory builds. Total average annual prices in 2016 for Brent crude oil, WTI crude oil, Henry Hub natural gas and our realized natural gas liquids all decreased by more than 5 percent when compared with 2015. In the fourth quarter of 2016, Brent crude oil, WTI crude oil, Henry Hub natural gas and our realized natural gas liquids prices all increased, compared with the same period of 2015. Given volatility in commodity price drivers and the business environment, price trends may not continue or reverse themselves.

Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil, bitumen, natural gas, natural gas liquids and LNG. The factors influencing these prices are beyond our control. Lower crude oil, bitumen, natural gas, natural gas liquids and LNG prices may have a material adverse effect on our revenues, operating income, cash flows and liquidity and on the amount of dividends we elect to declare and pay on our common stock. Lower prices may also limit the amount of reserves we can produce economically, adversely affecting our ability to maintain our reserve replacement ratio and accelerating the reduction in our existing reserve levels as we continue production from upstream fields.

Significant reductions in crude oil, bitumen, natural gas, natural gas liquids and LNG prices could also require us to reduce our capital expenditures or impair the carrying value of our assets. In the past two years, we recognized several impairments, which are described in Note 9—Impairments and the “APLNG” section of Note 7—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements. If commodity prices remain low relative to their historic levels, and as we continue to optimize our investments and exercise capital flexibility, it is reasonably likely we will incur future impairments to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method and unproved properties. Although it is not reasonably practicable to quantify the impact of any future impairments at this time, our results of operations could be adversely affected as a result.

***Our ability to declare and pay dividends is subject to certain considerations.***

Dividends are authorized and determined by our Board of Directors in its sole discretion and depend upon a number of factors, including:

- Cash available for distribution.
- Our results of operations and anticipated future results of operations.
- Our financial condition, especially in relation to the anticipated future capital needs of our properties.
- The level of reserves we establish for future capital expenditures.
- The level of distributions paid by comparable companies.
- Our operating expenses.
- Other factors our Board of Directors deems relevant.

We expect to continue to pay quarterly distributions to our stockholders; however, we bear all expenses incurred by our operations, and our funds generated by operations, after deducting these expenses, may not be sufficient to cover desired levels of distributions to our stockholders. Any downward revision in our distribution could have a material adverse effect on the market price of our common stock.

***We may need additional capital in the future, and it may not be available on acceptable terms.***

We have historically relied primarily upon cash generated by our operations to fund our operations and strategy, however we have also relied from time to time on access to the debt and equity capital markets for funding. There can be no assurance that additional debt or equity financing will be available in the future on acceptable terms, or at all. Our ability to obtain additional financing will be subject to a number of factors, including market conditions, our operating performance, investor sentiment and our ability to incur additional debt in compliance with agreements governing our then-outstanding debt. If we are unable to generate sufficient funds from operations or raise additional capital, our growth could be impeded.

In addition, we are regularly evaluated by the major rating agencies based on a number of factors, including our financial strength and conditions affecting the oil and gas industry generally. Due to the significant decline in prices for crude oil, bitumen, natural gas, natural gas liquids and LNG, and the expectation that these prices could remain depressed in the near future, the major ratings agencies conducted a review of the oil and gas industry and downgraded our debt ratings and those of several companies operating in the industry. Any downgrade in our credit rating, could increase the cost associated with any additional indebtedness we incur.

***Our business may be adversely affected by deterioration in the credit quality of, or defaults under our contracts with, third parties with whom we do business.***

The operation of our business requires us to engage in transactions with numerous counterparties operating in a variety of industries, including other companies operating in the oil and gas industry. These counterparties may default on their obligations to us as a result of operational failures or a lack of liquidity, or for other reasons, including bankruptcy. Market speculation about the credit quality of these counterparties, or their ability to continue performing on their existing obligations, may also exacerbate any operational difficulties or liquidity issues they are experiencing, particularly as it relates to other companies in the oil and gas industry as a result of the recent significant declines in commodity prices. Any default by any of our counterparties may result in our inability to perform obligations under agreements we have made with third parties or may otherwise adversely affect our business or results of operations. In addition, our rights against any of our counterparties as a result of a default may not be adequate to compensate us for the resulting harm caused or may not be enforceable at all in some circumstances.

***Unless we successfully add to our existing proved reserves, our future crude oil, bitumen, natural gas and natural gas liquids production will decline, resulting in an adverse impact to our business.***

The rate of production from upstream fields generally declines as reserves are depleted. Except to the extent that we conduct successful exploration and development activities, or, through engineering studies, optimize production performance or identify additional or secondary recovery reserves, our proved reserves will decline materially as we produce crude oil, bitumen, natural gas and natural gas liquids. Accordingly, to the extent we are unsuccessful in replacing the crude oil, bitumen, natural gas and natural gas liquids we produce with good prospects for future production, our business will experience reduced cash flows and results of operations. Any cash conservation efforts we may undertake as a result of commodity price declines may further limit our ability to replace depleted reserves.

***The exploration and production of oil and gas is a highly competitive industry.***

The exploration and production of crude oil, bitumen, natural gas and natural gas liquids is a highly competitive business. We compete with private, public and state-owned companies in all facets of the exploration and production business, including to locate and obtain new sources of supply and to produce oil, bitumen, natural gas and natural gas liquids in an efficient, cost-effective manner. Some of our competitors are larger and have greater resources than we do or may be willing to incur a higher level of risk than we are willing to incur to obtain potential sources of supply. If we are not successful in our competition for new reserves, our financial condition and results of operations may be adversely affected.

***Any material change in the factors and assumptions underlying our estimates of crude oil, bitumen, natural gas and natural gas liquids reserves could impair the quantity and value of those reserves.***

Our proved reserve information included in this annual report has been derived from engineering estimates prepared by our personnel. Reserve estimation is a process that involves estimating volumes to be recovered from underground accumulations of crude oil, bitumen, natural gas and natural gas liquids that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of reserves and future net cash flows based on the same available data. Any significant future price changes could have a material effect on the quantity and present value of our proved reserves. Any material changes in the factors and assumptions underlying our estimates of these items could result in a material negative impact to the volume of reserves reported or could cause us to incur impairment expenses on property associated with the production of those reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation. In addition to changes in the quantity and value of our proved reserves, the amount of crude oil, bitumen, natural gas and natural gas liquids that can be obtained from any proved reserve may ultimately be different from those estimated prior to extraction.

***We expect to continue to incur substantial capital expenditures and operating costs as a result of our compliance with existing and future environmental laws and regulations. Likewise, future environmental laws and regulations, such as limitations on greenhouse gas emissions, may impact or limit our current business plans and reduce demand for our products.***

Our businesses are subject to numerous laws and regulations relating to the protection of the environment. These laws and regulations continue to increase in both number and complexity and affect our operations with respect to, among other things:

- The discharge of pollutants into the environment.
- Emissions into the atmosphere, such as nitrogen oxides, sulfur dioxide, mercury and greenhouse gas emissions.
- Carbon taxes.
- The handling, use, storage, transportation, disposal and cleanup of hazardous materials and hazardous and nonhazardous wastes.
- The dismantlement, abandonment and restoration of our properties and facilities at the end of their useful lives.
- Exploration and production activities in certain areas, such as offshore environments, arctic fields, oil sands reservoirs and tight oil plays.

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our business, financial condition, results of operations and cash flows in future periods could be materially adversely affected.

Although our business operations are designed and operated to accommodate expected climatic conditions, to the extent there are significant changes in the Earth's climate, such as more severe or frequent weather conditions in the markets we serve or the areas where our assets reside, we could incur increased expenses, our operations could be materially impacted, and demand for our products could fall. Demand for our products may also be adversely affected by conservation plans and efforts undertaken in response to global climate change, including plans developed in connection with the Paris climate conference in December 2015. Many governments also provide, or may in the future provide, tax advantages and other subsidies to support the use and development of alternative energy technologies. Our operations and the demand for our products could be materially impacted by the development and adoption of these technologies.

***Domestic and worldwide political and economic developments could damage our operations and materially reduce our profitability and cash flows.***

Actions of the U.S., state, local and foreign governments, through tax and other legislation, executive order and commercial restrictions, could reduce our operating profitability both in the United States and abroad. In certain locations, governments have imposed or proposed restrictions on our operations; special taxes or tax assessments; and payment transparency regulations that could require us to disclose competitively sensitive information or might cause us to violate non-disclosure laws of other countries. U.S. federal, state and local legislative and regulatory agencies' initiatives regarding the hydraulic fracturing process could result in operating restrictions or delays in the completion of our oil and gas wells.

The U.S. government can also prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries. Actions by host governments have affected operations significantly in the past, such as the expropriation of our oil assets by the Venezuelan government, and may continue to do so in the future. Changes in domestic and international regulations may affect our ability to obtain or maintain permits, including those necessary for drilling and development of wells or for construction of LNG terminals or regasification facilities in various locations.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 58 percent of our hydrocarbon production was derived from production outside the United States in 2016, and 55 percent of our proved reserves, as of December 31, 2016, was located outside the United States. We are subject to risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas, bitumen, natural gas liquids or LNG pricing and taxation, other political, economic or diplomatic developments, changing political conditions and international monetary fluctuations. In particular, some countries where we operate lack well-developed legal systems or have not adopted clear legal and regulatory frameworks for oil and gas exploration and production. This lack of legal certainty exposes our operations to increased risks, including increased difficulty in enforcing our agreements in those jurisdictions and increased risks of adverse actions by local government authorities, such as expropriations.

***Changes in governmental regulations may impose price controls and limitations on production of crude oil, bitumen, natural gas and natural gas liquids.***

Our operations are subject to extensive governmental regulations. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of crude oil, bitumen, natural gas and natural gas liquids wells below actual production capacity. Because legal requirements are frequently changed and subject to interpretation, we cannot predict the effect of these requirements.

***Our investments in joint ventures decrease our ability to manage risk.***

We conduct many of our operations through joint ventures in which we may share control with our joint venture partners. There is a risk our joint venture participants may at any time have economic, business or legal interests or goals that are inconsistent with those of the joint venture or us, or our joint venture partners may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone. Failure by us, or an entity in which we have a joint venture interest, to adequately manage the risks associated with any acquisitions or joint ventures could have a material adverse effect on the financial condition or results of operations of our joint ventures and, in turn, our business and operations.

***We may not be able to successfully complete any disposition we elect to pursue.***

From time to time, we may seek to divest portions of our business or investments that are not important to our ongoing strategic objectives. Any dispositions we undertake may involve numerous risks and uncertainties, any of which could adversely affect our results of operations or financial condition. In particular, we may not be able to successfully complete any disposition on a timeline or on terms acceptable to us, if at all, whether due to market conditions, regulatory challenges or other concerns. In addition, the reinvestment of capital from disposition proceeds may not ultimately yield investment returns in line with our internal or external expectations. Any dispositions we pursue may also result in disruption to other parts of our business, including through the diversion of resources and management attention from our ongoing business and other strategic matters, or through the disruption of relationships with our employees and key vendors. Further, in connection with any disposition, we may enter into transition services agreements or undertake indemnity or other obligations that may result in additional expenses for us.

***We do not insure against all potential losses; therefore, we could be harmed by unexpected liabilities and increased costs.***

We maintain insurance against many, but not all, potential losses or liabilities arising from operating risks. As such, our insurance coverage may not be sufficient to fully cover us against potential losses arising from such risks. Uninsured losses and liabilities arising from operating risks could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

***Our operations present hazards and risks that require significant and continuous oversight.***

The scope and nature of our operations present a variety of significant hazards and risks, including operational hazards and risks such as explosions, fires, crude oil spills, severe weather, geological events, labor disputes, terrorist attacks, sabotage, civil unrest or cyber attacks. Our operations may also be adversely affected by unavailability, interruptions or accidents involving services or infrastructure required to develop, produce, process or transport our production, such as contract labor, drilling rigs, pipelines, railcars, tankers, barges or other infrastructure. Our operations are subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. Activities in deepwater areas may pose incrementally greater risks because of complex subsurface conditions such as higher reservoir pressures, water depths and metocean conditions. All such hazards could result in loss of human life, significant property and equipment damage, environmental pollution, impairment of operations, substantial losses to us and damage to our reputation. Further, our business and operations may be disrupted if we do not respond, or are perceived not to respond, in an appropriate manner to any of these hazards and risks or any other major crisis or if we are unable to efficiently restore or replace affected operational components and capacity.

Our technologies, systems and networks may be subject to cybersecurity breaches. Although we have experienced occasional, actual or attempted breaches of our cybersecurity, none of these breaches has had a material effect on our business, operations or reputation. If our systems for protecting against cybersecurity risks prove to be insufficient, we could be adversely affected by having our business systems compromised, our proprietary information altered, lost or stolen, or our business operations disrupted. As cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information systems and related infrastructure security vulnerabilities.

## Item 1B. UNRESOLVED STAFF COMMENTS

None.

## Item 3. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the fourth quarter of 2016, as well as matters previously reported in our 2015 Form 10-K and our first-, second- and third-quarter 2016 Form 10-Qs that were not resolved prior to the fourth quarter of 2016. Material developments to the previously reported matters have been included in the descriptions below. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings were to be decided adversely to ConocoPhillips, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to SEC regulations.

On April 30, 2012, the separation of our downstream business was completed, creating two independent energy companies: ConocoPhillips and Phillips 66. In connection with the separation, we entered into an Indemnification and Release Agreement, which provides for cross-indemnities between Phillips 66 and us and established procedures for handling claims subject to indemnification and related matters, such as legal proceedings. We have included matters where we remain or have subsequently become a party to a proceeding relating to Phillips 66, in accordance with SEC regulations. We do not expect any of those matters to result in a net claim against us.

*New Matters—ConocoPhillips*
A Judgment and Consent Decree was entered on December 7, 2016, by the South Central Judicial District Court in Burleigh County, North Dakota against Burlington Resources Oil & Gas Company LP and ConocoPhillips Company resolving alleged violations of the state's air pollution control laws. The North Dakota Department of Health was the Plaintiff in this matter. The Consent Decree requires the companies to implement a specified program to inspect and repair as necessary its facilities in North Dakota and to pay a penalty of approximately $220,000.

*Matters Previously Reported—Phillips 66*
In October 2007, we received a Complaint from the U.S. Environmental Protection Agency (EPA) alleging violations of the Clean Water Act related to a 2006 oil spill at the Bayway Refinery and proposing a penalty of $156,000. Phillips 66 resolved this matter with the EPA in December 2016 with a settlement payment of $35,500.

In May 2012, the Illinois Attorney General's office filed and notified ConocoPhillips of a complaint with respect to operations at the Phillips 66 WRB Wood River Refinery alleging violations of the Illinois groundwater standards and a third-party's hazardous waste permit. The complaint seeks as relief remediation of area groundwater; compliance with the hazardous waste permit; enhanced pipeline and tank integrity measures; additional spill reporting; and yet-to-be specified amounts for fines and penalties.

*New Matters—Phillips 66*
In October 2016, after Phillips 66 received a Notice of Intent to Sue from the Sierra Club, Phillips 66 entered into a voluntary settlement with the Illinois Environmental Protection Agency for alleged violations of wastewater requirements at the Wood River Refinery occurring in part prior to the separation. The settlement involves certain capital projects and payment of $125,000. The settlement has been filed with the Court for final approval and the Sierra Club has sought to intervene in the case to oppose the settlement. A court hearing is scheduled for March 2017.

## Item 4. MINE SAFETY DISCLOSURES

Not applicable.

**EXECUTIVE OFFICERS OF THE REGISTRANT**

| Name | Position Held | Age* |
|---|---|---|
| Janet L. Carrig | Senior Vice President, Legal, General Counsel and Corporate Secretary | 59 |
| Ellen R. DeSanctis | Vice President, Investor Relations and Communications | 60 |
| Matt J. Fox | Executive Vice President, Strategy, Exploration and Technology | 56 |
| Alan J. Hirshberg | Executive Vice President, Production, Drilling and Projects | 55 |
| Ryan M. Lance | Chairman of the Board of Directors and Chief Executive Officer | 54 |
| Andrew D. Lundquist | Senior Vice President, Government Affairs | 56 |
| James D. McMorran | Vice President, Human Resources, Real Estate and Facilities Services | 59 |
| Glenda M. Schwarz | Vice President and Controller | 51 |
| Don E. Wallette, Jr. | Executive Vice President, Finance, Commercial and Chief Financial Officer | 58 |

**On February 15, 2017.*

There are no family relationships among any of the officers named above. Each officer of the company is elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and thereafter as appropriate. Each officer of the company holds office from the date of election until the first meeting of the directors held after the next Annual Meeting of Stockholders or until a successor is elected. The date of the next annual meeting is May 16, 2017. Set forth below is information about the executive officers.

**Janet L. Carrig** was appointed Senior Vice President, Legal, General Counsel and Corporate Secretary in 2007.

**Ellen R. DeSanctis** was appointed Vice President, Investor Relations and Communications in May 2012. She was previously employed by Petrohawk Energy Corp. and served as Senior Vice President, Corporate Communications since 2010. Prior to that she was employed by Rosetta Resources Inc. and served as Executive Vice President of Strategy and Development from 2008 to 2010.

**Matt J. Fox** was appointed as Executive Vice President, Strategy, Exploration and Technology in April 2016. He previously served as the Executive Vice President, Exploration and Production, from 2012 to 2016. Prior to that, he was employed by Nexen, Inc. and served as Executive Vice President, International since 2010.

**Alan J. Hirshberg** was appointed Executive Vice President, Production, Drilling and Projects in April 2016. He previously served as Executive Vice President, Technology and Projects, from 2012 to 2016. Prior to that, he served as Senior Vice President, Planning and Strategy since 2010.

**Ryan M. Lance** was appointed Chairman of the Board of Directors and Chief Executive Officer in May 2012, having previously served as Senior Vice President, Exploration and Production—International since May 2009.

**Andrew D. Lundquist** was appointed Senior Vice President, Government Affairs in 2013. Prior to that, he served as managing partner of BlueWater Strategies LLC, since 2002.

**James D. McMorran** was appointed Vice President, Human Resources, Real Estate and Facilities Services in August 2015. Prior to that, he served as Manager, Compensation and Benefits, since 2004.

**Glenda M. Schwarz** was appointed Vice President and Controller in 2009.

**Don E. Wallette, Jr.** was appointed Executive Vice President, Finance, Commercial and Chief Financial Officer in April 2016. He previously served as Executive Vice President, Commercial, Business Development and Corporate Planning from 2012 to 2016. Prior to that, he served as President, Asia Pacific since 2010 and President, Russia/Caspian from 2006 to 2010.

## PART II

### Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

**Quarterly Common Stock Prices and Cash Dividends Per Share**

ConocoPhillips' common stock is traded on the New York Stock Exchange, under the symbol "COP."

| | | Stock Price | | |
|---|---|---|---|---|
| | | High | Low | Dividends |
| **2016** | | | | |
| First | **$** | **47.77** | **31.05** | **0.25** |
| Second | | **49.35** | **38.19** | **0.25** |
| Third | | **44.42** | **38.80** | **0.25** |
| Fourth | | **53.17** | **40.37** | **0.25** |
| 2015 | | | | |
| First | $ | 70.11 | 60.57 | 0.73 |
| Second | | 69.72 | 60.86 | 0.73 |
| Third | | 61.51 | 41.10 | 0.74 |
| Fourth | | 57.24 | 44.56 | 0.74 |

| | | |
|---|---|---|
| Closing Stock Price at December 31, 2016 | $ | 50.14 |
| Closing Stock Price at January 31, 2017 | $ | 48.76 |
| Number of Stockholders of Record at January 31, 2017* | | 49,845 |

**In determining the number of stockholders, we consider clearing agencies and security position listings as one stockholder for each agency listing.*

The declaration of dividends is subject to the discretion of our Board of Directors, and may be affected by various factors, including our future earnings, financial condition, capital requirements, levels of indebtedness, credit ratings and other considerations our Board of Directors deems relevant. Our Board of Directors has adopted a quarterly dividend declaration policy providing that the declaration of any dividends will be determined quarterly by the Board of Directors taking into account such factors as our business model, prevailing business conditions and our financial results and capital requirements, without a predetermined annual net income payout ratio.

On February 4, 2016, we announced that our Board of Directors approved a reduction in the quarterly dividend to $0.25 per share, compared with the previous quarterly dividend of $0.74 per share.

On January 31, 2017, we announced that our Board of Directors approved an increase in the quarterly dividend to $0.265 per share, compared with the previous quarterly dividend of $0.25 per share.

**Issuer Purchases of Equity Securities**

| Period | Total Number of Shares Purchased* | Average Price Paid Per Share | Shares Purchased as Part of Publicly Announced Plans or Programs | Millions of Dollars Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| October 1-31, 2016 | - | $ - | - | $ - |
| November 1-30, 2016 | 695,393 | 45.30 | 695,393 | 2,969 |
| December 1-31, 2016 | 1,883,705 | 50.16 | 1,883,705 | 2,874 |
| Total fourth-quarter 2016 | 2,579,098 | $ 48.85 | 2,579,098 | |

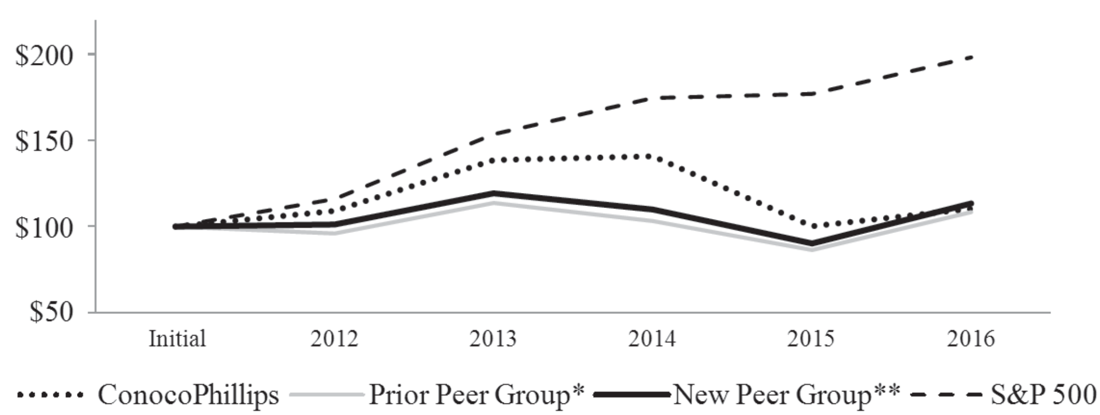
**There were no repurchases of common stock from company employees in connection with the company's broad-based employee incentive plans.*

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock over the next three years. Repurchase of shares began in November and totaled 2,579,098 shares at a cost of $126 million, through December 31, 2016. Acquisitions for the share repurchase program are made at management's discretion, at prevailing prices, subject to market conditions and other factors. Repurchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan are held as treasury shares.

**Stock Performance Graph**

The following graph shows the cumulative total shareholder return (TSR) for ConocoPhillips' common stock in each of the five years from December 31, 2011, to December 31, 2016. The graph also compares the cumulative total returns for the same five-year period with the S&P 500 Index, the performance peer group used in the prior fiscal year (the "Prior Peer Group") and a new performance peer group for the current fiscal year (the "New Peer Group"). The Prior Peer Group consisted of BP, Chevron, ExxonMobil, Royal Dutch Shell, Total, Anadarko, Apache, BG Group plc, Devon and Occidental, weighted according to the respective peer's stock market capitalization at the beginning of each annual period. The New Peer Group excludes BG Group plc due to its acquisition by Royal Dutch Shell in 2016 and includes Marathon Oil Corporation. The Prior Peer Group is presented for purposes of comparison. The comparison assumes $100 was invested on December 31, 2011, in ConocoPhillips stock, the S&P 500 Index, the Prior Peer Group and New Peer Group and assumes that all dividends were reinvested. The spinoff of Phillips 66 in 2012 is treated as a special dividend for the purposes of calculating TSR for ConocoPhillips. The market value of the distributed shares on the spinoff date was deemed reinvested in shares of ConocoPhillips common stock.

**Five-Year Cumulative Total Shareholder Returns**




**Prior Peer Group: BP; Chevron; ExxonMobil; Royal Dutch Shell; Total; Anadarko; Apache; BG Group plc; Devon; Occidental.*
***New Peer Group: BP; Chevron; ExxonMobil; Royal Dutch Shell; Total; Anadarko; Apache; Marathon Oil Corporation; Devon; Occidental.*

## Item 6. SELECTED FINANCIAL DATA

| | Millions of Dollars Except Per Share Amounts | | | | |
|---|---|---|---|---|---|
| | **2016** | 2015 | 2014 | 2013 | 2012 |
| Sales and other operating revenues | $ **23,693** | 29,564 | 52,524 | 54,413 | 57,967 |
| Income (loss) from continuing operations | **(3,559)** | (4,371) | 5,807 | 8,037 | 7,481 |
| Per common share | | | | | |
| Basic | **(2.91)** | (3.58) | 4.63 | 6.47 | 5.95 |
| Diluted | **(2.91)** | (3.58) | 4.60 | 6.43 | 5.91 |
| Income from discontinued operations | **-** | - | 1,131 | 1,178 | 1,017 |
| Net income (loss) | **(3,559)** | (4,371) | 6,938 | 9,215 | 8,498 |
| Net income (loss) attributable to ConocoPhillips | **(3,615)** | (4,428) | 6,869 | 9,156 | 8,428 |
| Per common share | | | | | |
| Basic | **(2.91)** | (3.58) | 5.54 | 7.43 | 6.77 |
| Diluted | **(2.91)** | (3.58) | 5.51 | 7.38 | 6.72 |
| Total assets | **89,772** | 97,484 | 116,539 | 118,057 | 117,144 |
| Long-term debt | **26,186** | 23,453 | 22,383 | 21,073 | 20,770 |
| Joint venture acquisition obligation—long-term | **-** | - | - | - | 2,810 |
| Cash dividends declared per common share | **1.00** | 2.94 | 2.84 | 2.70 | 2.64 |

Net income (loss) and Net income (loss) attributable to ConocoPhillips from 2012 to 2014 includes income from discontinued operations as a result of the separation of the downstream business, the sale of our interest in Kashagan, and the sales of our Algeria and Nigeria businesses. These factors impact the comparability of this information. For additional information on the sale of our Nigeria business, see Note 3—Discontinued Operations, in the Notes to Consolidated Financial Statements.

See Management's Discussion and Analysis of Financial Condition and Results of Operations and the Notes to Consolidated Financial Statements for a discussion of factors that will enhance an understanding of this data.

## Item 7. 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 financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. 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 the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 72.*

*Due to discontinued operations reporting, we believe income (loss) from continuing operations is more representative of ConocoPhillips' earnings than overall net income (loss) attributable to ConocoPhillips. The terms "earnings" and "loss" as used in Management's Discussion and Analysis refer to income (loss) from continuing operations. For additional information, see Note 3—Discontinued Operations, in the Notes to Consolidated Financial Statements.*

### BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

ConocoPhillips is the world's largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. Headquartered in Houston, Texas, we have operations and activities in 17 countries. Our diverse portfolio primarily includes resource-rich North American unconventional assets and oil sands assets in Canada; lower-risk conventional assets in North America, Europe, Asia and Australia; several liquefied natural gas (LNG) developments; and an inventory of global conventional and unconventional exploration prospects. At December 31, 2016, we employed approximately 13,300 people worldwide and had total assets of $90 billion. Our stock is listed on the New York Stock Exchange under the symbol "COP."

#### Overview

The energy landscape remained challenged throughout 2016. Global production oversupply caused continued weakness in commodity prices in 2016 following a year of weak prices in 2015. Ongoing uncertainty around the timing and trajectory of a price recovery, coupled with tightening credit capacity across the industry, caused us to take actions early in the year to mitigate the impacts of possible prolonged weak prices. We reduced our quarterly dividend by 66 percent, to $0.25 per share, issued $3.0 billion of long-term debt, obtained a $1.6 billion three-year term loan, reduced capital expenditures and production and operating expenses, and further streamlined our portfolio.

Our capital expenditures in 2016 were $4.9 billion, a 52 percent reduction compared with 2015 and a 72 percent reduction compared with 2014. Production and operating expenses in 2016 were $5.7 billion, down 19 percent compared with 2015 and down 36 percent compared with 2014.

We also progressed our efforts to high-grade our portfolio. In 2016, we generated $1.3 billion from the disposition of certain non-core assets in our portfolio, including the offshore South Natuna Sea Block B in Indonesia and ConocoPhillips Senegal B.V., the entity that held our interest in three exploration blocks offshore Senegal. The full-year 2016 production impact of completed dispositions was 27 thousand barrels of oil equivalent per day (MBOED).

During 2016, we expanded our value proposition to position the company for long-term success in light of our view that commodity prices, specifically oil prices, are likely to remain lower and be more volatile in the future. Our value proposition principles, namely to maintain a strong balance sheet, grow our dividend and pursue disciplined growth, remain essentially unchanged. However, we took steps to improve our competitiveness and resilience by establishing clear priorities for allocating future cash flows.

In order, these priorities are: invest capital at a level that maintains flat production volumes and pays our existing dividend; grow our existing dividend; reduce debt to a level we believe is sufficient to maintain a strong investment grade rating through price cycles; repurchase shares; and invest capital to grow absolute production. We outlined a 2017 to 2019 operating plan that achieves these priorities at Brent prices at or above $50 per barrel with asset sales of $5 billion to $8 billion.

We believe we have taken prudent actions to position the company for success in an environment of price uncertainty and ongoing volatility, while accomplishing significant milestones in a challenged business environment throughout 2016.

**Key Operating and Financial Summary**

Significant items during 2016 included the following:

- Achieved full-year production excluding Libya of 1,567 MBOED; 3 percent production growth adjusted for downtime and dispositions.
- Capital expenditures of $4.9 billion, a more than 50 percent reduction compared with 2015.
- Reduced production and operating expenses by 19 percent year over year.
- Achieved project startups at APLNG Train 2 in Australia, Foster Creek Phase G and Christina Lake Phase F in Canada, Alder in Europe, Malikai in Malaysia, and Bohai wellhead platform J in China.
- Significant discovery at Willow prospect in Alaska.
- Generated proceeds of $1.3 billion from asset dispositions.
- Announced preliminary year-end proved reserves of 6.4 billion BOE.
- Initiated $3 billion share buyback program in mid-November.

**Business Environment**

Global oil market conditions in 2016 were challenging as the excess of supply relative to global demand led to another year of global inventory builds. Global oil prices experienced elevated levels of volatility throughout 2016 with first quarter Brent crude oil prices reaching a 10-year quarterly average low of $33.89 per barrel. Prices recovered slightly in the second and third quarters of 2016 as production growth slowed while demand continued to increase. In the fourth quarter, prices continued to trend higher, with Brent crude oil averaging $49.46 per barrel, as OPEC members and key non-OPEC producers agreed to cut production in 2017.

The energy industry has periodically experienced this type of extreme volatility due to fluctuating supply-and-demand conditions. Commodity prices are the most significant factor impacting our profitability and related reinvestment of operating cash flows into our business. Among other dynamics that could influence world energy markets and commodity prices are global economic health, supply disruptions or fears thereof caused by civil unrest or military conflicts, actions taken by OPEC, environmental laws, tax regulations, governmental policies and weather-related disruptions. North America’s energy landscape has been transformed from resource scarcity to an abundance of supply, primarily due to advances in technology responsible for the rapid growth of tight oil production, successful exploration and rising production from the Canadian oil sands. Our strategy is to create value through price cycles by delivering on the financial and operational priorities that underpin our value proposition.

*Financial Priorities*
The financial priorities we believe will drive our success through the price cycles include:

- Control costs and expenses. Controlling operating and overhead costs, without compromising safety and environmental stewardship, is a high priority. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Managing operating and overhead costs is critical to maintaining a competitive position in our industry, particularly in a low commodity price environment. The ability to control our operating and overhead costs impacts our ability to deliver strong cash from operations.

- Maintain a strong balance sheet. We believe financial strength is critical in a cyclical business such as ours. In early 2016, ongoing uncertainty around the timing of a price recovery, coupled with tightening credit capacity across the industry, caused us to take actions to preserve our balance sheet strength and mitigate the impacts of possible weak prices in 2016 and 2017. During the first quarter of 2016, we reduced our quarterly dividend and issued additional debt to secure liquidity. Realized commodity prices improved subsequent to the first quarter of 2016, and we paid down approximately $2.3 billion of debt during the second half of the year. In November 2016, we announced our plan to reduce debt to $20 billion by year-end 2019. We expect to retire outstanding debt as it matures and exercise flexibility in paying down our term loan, which is due in 2019.

- Return capital to shareholders. In 2016, we paid dividends on our common stock of $1.3 billion. We believe in delivering value to our shareholders through the price cycles. As a result, we have set a priority to increase our dividend rate annually and purchase up to $3 billion of our common stock over the next three years. We began repurchasing shares in November 2016, and in January 2017, we announced a 6 percent increase to our quarterly dividend, from $0.25 per share to $0.265 per share.

- Focus on financial returns. This is a core aspect of our value proposition. Our goal is to achieve strong financial returns by controlling our costs, high-grading our portfolio, shifting our production mix, and exercising capital discipline.

*Operational Priorities*
The operational priorities we must manage well to be successful include:

- Maintain capital discipline. We participate in a commodity price-driven and capital-intensive industry, with varying lead times from when an investment decision is made to the time an asset is operational and generates cash flow. As a result, we must invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, and construct pipelines and LNG facilities. Given our view of greater price volatility, we have shifted our capital allocation to focus on value-preserving, shorter cycle time and low cost-of-supply unconventional programs in our resource base. Our cash allocation priorities call for the investment of sufficient capital to maintain production and pay the existing dividend. Additional allocations of capital toward absolute growth will be dependent on satisfaction of other financial priorities. We use a disciplined approach, focused on value maximization, to set our capital plans.

  In November 2016, we announced a 2017 capital budget of $5 billion.

- Optimize our portfolio. We continue to optimize our asset portfolio by focusing on low cost-of-supply assets which strategically fit our development plans. In the third quarter of 2015, we announced plans to reduce future capital spending in our deepwater exploration program. Subsequently, in 2016, we sold our interests in several exploration areas, including offshore Senegal, and terminated our final Gulf of Mexico deepwater drillship contract. Additionally, during the year, we sold our 40 percent working interest in the offshore South Natuna Sea Block B Production Sharing Contract (PSC) in Indonesia and our 30 percent interest in an exploration license offshore

Newfoundland. We generated approximately $1.3 billion in proceeds from non-core asset dispositions in 2016.

In November 2016, we announced our plan to divest between $5 billion and $8 billion of assets, primarily associated with North American natural gas, over the next two years. Proceeds from the sale of assets will be directed toward the achievement of our financial priorities. We will continue to evaluate our assets to determine whether they fit our strategic direction and will optimize the portfolio as necessary, directing our capital investments to areas that align with our objectives.

- <u>Maintain a relentless focus on safety and environmental stewardship</u>. Safety and environmental stewardship, including the operating integrity of our assets, remain our highest priorities, and we are committed to protecting the health and safety of everyone who has a role in our operations and the communities in which we operate. We strive to conduct our business with respect and care for both the local and global environment and systematically manage risk to drive sustainable business growth. Our sustainability efforts in 2016 focused on updating action plans for climate change, biodiversity, water and human rights, as well as revamping public reporting to be more informative, searchable and responsive to common questions. We are committed to building a learning organization using human performance principles as we relentlessly pursue improved Health, Safety and Environment (HSE) and operational performance.

- <u>Add to our proved reserve base</u>. We primarily add to our proved reserve base in two ways:

  - Successful exploration, exploitation and development of new and existing fields.
  - Application of new technologies and processes to improve recovery from existing fields.

  Proved reserve estimates require economic production based on historical 12-month, first-of-month, average prices and current costs. Therefore, our proved reserves generally decrease as prices decline and increase as prices rise. Additionally, as we continue cash conservation efforts, our reserve replacement efforts could be delayed thus limiting our ability to replace depleted reserves. Low commodity prices and reduced capital expenditures in 2016 adversely affected our reported year-end proved reserves. In 2016, our reserve replacement was negative 194 percent. In the five years ended December 31, 2016, our reserve replacement was 35 percent. We expect our proved reserves to increase if prices rise.

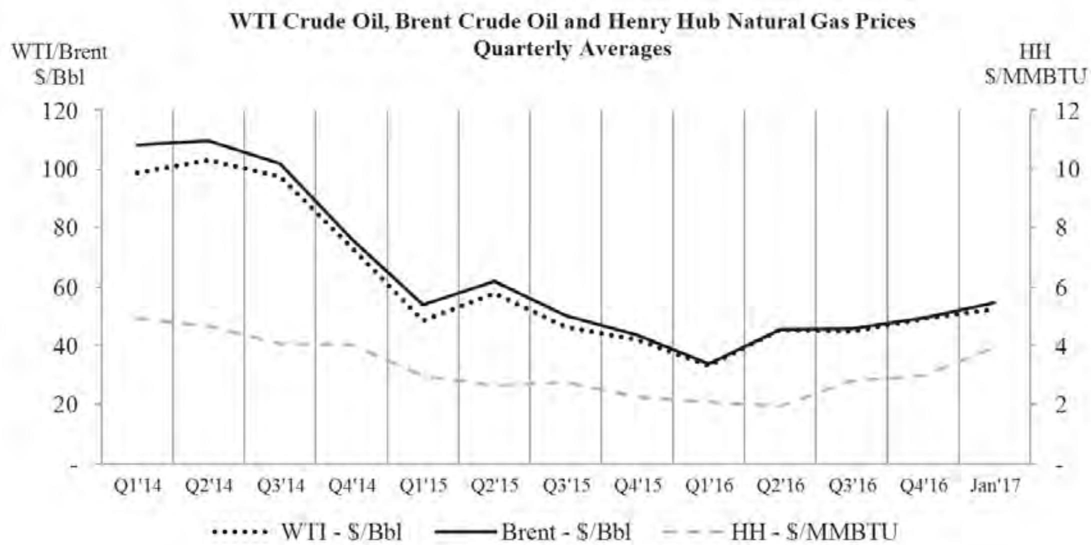
  Access to additional resources may become increasingly difficult as commodity prices can make projects uneconomic or unattractive. In addition, prohibition of direct investment in some nations, national fiscal terms, political instability, competition from national oil companies, and lack of access to high-potential areas due to environmental or other regulation may negatively impact our ability to increase our reserve base. As such, the timing and level at which we add to our reserve base may, or may not, allow us to replace our production over subsequent years.

- <u>Apply technical capability</u>. We leverage our knowledge and technology to create value and safely deliver on our plans. Technical strength is part of our heritage, and we are evolving our technical approach to optimally apply best practices. Companywide, we continue to evaluate potential solutions to leverage knowledge of technological successes across our operations. Such innovations enable us to economically convert additional resources to reserves, achieve greater operating efficiencies and reduce our environmental impact.

- <u>Develop and retain a talented work force</u>. We strive to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics. To this end, we offer university internships across multiple disciplines to attract the best talent and, as needed, recruit experienced hires to maintain a broad range of skills and experience. We promote continued learning, development and technical training through structured development programs designed to enhance the technical and functional skills of our employees.

*Other Factors Affecting Profitability*
Other significant factors that can affect our profitability include:

- Commodity prices. Our earnings and operating cash flows generally correlate with industry price levels for crude oil and natural gas, the prices of which are subject to factors external to the company and over which we have no control. The following graph depicts the average benchmark prices for West Texas Intermediate (WTI) crude oil, Dated Brent crude oil and U.S. Henry Hub natural gas:




Brent crude oil prices averaged $49.46 per barrel in the fourth quarter of 2016, an increase of 13 percent compared with $43.67 per barrel in the fourth quarter of 2015. Similarly, WTI crude oil prices increased 17 percent from $42.10 per barrel in the fourth quarter of 2015 to $49.18 per barrel in the same period of 2016.

Despite the fourth quarter increase, crude oil prices were under pressure throughout 2016 due to a continued global production increase that outpaced demand growth, leading to a large observed rise in global inventory. The average Brent crude oil price decreased 17 percent, from $52.46 per barrel in 2015 to $43.69 per barrel in 2016.

Henry Hub natural gas prices averaged $2.98 per million British thermal units (MMBTU) in the fourth quarter of 2016, an increase of 31 percent compared with $2.27 per MMBTU in the fourth quarter of 2015. Natural gas prices increased in the fourth quarter due to growth in demand, coupled with declining production.

On average, Henry Hub natural gas prices decreased 8 percent from $2.67 per MMBTU in 2015 to $2.46 per MMBTU in 2016, mainly due to strong production levels and a warmer-than expected winter reducing demand below expectations. In 2016, U.S. underground gas storage inventories reached their highest levels in five years.

Our realized natural gas liquids prices averaged $21.82 per barrel in the fourth quarter of 2016, an increase of 33 percent compared with $16.42 per barrel in the same quarter of 2015.

Similar to natural gas and crude oil, our natural gas liquids prices also declined on average in 2016. Our average realized natural gas liquids prices decreased 6 percent, from $17.79 per barrel in 2015 to $16.68 per barrel in 2016, as the expansion in tight oil production boosted supplies of natural gas liquids, resulting in continued downward pressure on natural gas liquids prices in the United States.

Declining global crude oil prices resulted in the Western Canada Select benchmark price experiencing a 17 percent decline, from $35.21 per barrel in 2015 to $29.36 per barrel in 2016. Consequently, our realized bitumen price experienced a decrease relative to 2015 price levels. Our realized bitumen price was $15.27 per barrel in 2016, a decrease of 18 percent compared with $18.72 per barrel in the same period of 2015.

Our worldwide annual average realized price was $28.35 per barrel of oil equivalent (BOE) in 2016, a decrease of 17 percent compared with $34.34 per BOE in 2015. The reduction in the prices reflects lower average realized prices across all commodities.

In recent years, the use of hydraulic fracturing and horizontal drilling in tight oil formations has led to increased industry actual and forecasted crude oil and natural gas production in the United States. Although providing significant short- and long-term growth opportunities for our company, the increased abundance of crude oil and natural gas due to development of tight oil plays could also have adverse financial implications to us, including: an extended period of low commodity prices; production curtailments; delay of plans to develop areas such as unconventional fields or Alaska North Slope natural gas fields; and underutilization of LNG regasification facilities. Should one or more of these events occur, our revenues would be reduced and additional asset impairments might be possible.

- Impairments. As mentioned above, we participate in a capital-intensive industry. At times, our properties, plants and equipment and investments become impaired when, for example, commodity prices decline significantly for long periods of time, our reserve estimates are revised downward, or a decision to dispose of an asset leads to a write-down to its fair value. We may also invest large amounts of money in exploration which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. In 2016, we recorded before-tax impairments of $139 million for proved properties and $466 million for unproved properties. As we optimize our assets in the future, it is reasonably possible we may incur future losses upon sale or impairment charges to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method, and unproved properties. For additional information on our impairments in 2016, 2015 and 2014, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

- Effective tax rate. Our operations are located in countries with different tax rates and fiscal structures. Accordingly, even in a stable commodity price and fiscal/regulatory environment, our overall effective tax rate can vary significantly between periods based on the “mix” of before-tax earnings within our global operations.

- Fiscal and regulatory environment. Our operations can be affected by changing economic, regulatory and political environments in the various countries in which we operate, including the United States. Civil unrest or strained relationships with governments may impact our operations or investments. These changing environments have generally negatively impacted our results of operations, and further changes to government fiscal take could have a negative impact on future operations. Our production operations in Libya and related oil exports were suspended or significantly curtailed from July 2013 to October 2016 due to the closure of the Es Sider crude oil export terminal, and they were also suspended in 2011 during Libya’s period of civil unrest. In 2016, the United Kingdom government enacted tax legislation which reduced our U.K. corporate tax rate by 10 percent. Our assets in Venezuela and Ecuador were expropriated in 2007 and 2009, respectively. Our management carefully considers these events when evaluating projects or determining the level of activity in such countries.

**Outlook**

Full-year 2017 production is expected to be 1,540 to 1,570 MBOED. This results in flat to 2 percent growth compared with full-year 2016 production of 1,540 MBOED when adjusted for 2016 dispositions of 27 MBOED. First-quarter 2017 production is expected to be 1,540 to 1,580 MBOED. Production guidance for 2017 excludes Libya and the impact of future dispositions.

*Marketing Activities*
In line with our strategic objectives, we are currently marketing certain non-core assets primarily associated with North American natural gas. We expect to generate \$5 billion to \$8 billion in proceeds over the next two years from asset sales.

**Operating Segments**

We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, corporate overhead, certain technology activities, as well as licensing revenues received.

Our key performance indicators, shown in the statistical tables provided at the beginning of the operating segment sections that follow, reflect results from our continuing operations, including commodity prices and production.

## RESULTS OF OPERATIONS

### Consolidated Results

A summary of the company's income (loss) from continuing operations by business segment follows:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| Years Ended December 31 | | **2016** | 2015 | 2014 |
| Alaska | **$** | **319** | 4 | 2,041 |
| Lower 48 | | **(2,257)** | (1,932) | (22) |
| Canada | | **(935)** | (1,044) | 940 |
| Europe and North Africa | | **394** | 409 | 814 |
| Asia Pacific and Middle East | | **265** | (406) | 3,008 |
| Other International | | **(16)** | (593) | (100) |
| Corporate and Other | | **(1,329)** | (809) | (874) |
| Income (loss) from continuing operations | **$** | **(3,559)** | (4,371) | 5,807 |

*2016 vs. 2015*

Losses for ConocoPhillips decreased 19 percent in 2016. The decrease was mainly due to:

- Lower exploration expenses. Exploration expenses decreased mainly due to reduced leasehold impairment expense and dry hole costs.
- Lower proved property and equity investment impairments, including the absence of a $1.5 billion before- and after-tax impairment of our equity investment in Australia Pacific LNG Pty Ltd (APLNG) in 2015.
- Lower production and operating expenses.
- A $161 million net deferred tax benefit resulting from a reduction in the U.K. tax rate, which was enacted in September 2016 and effective January 1, 2016.
- The absence of a $129 million deferred tax charge from increased corporate tax rates in Canada in 2015.

The decrease in losses was partly offset by:

- Lower commodity prices.
- The absence of a $555 million net deferred tax benefit resulting from a change in the U.K. tax rate in 2015.
- Lower crude oil, natural gas liquids, and gas sales volumes.
- Lower equity earnings, primarily driven by increased depreciation, depletion and amortization (DD&A) expense, as well as a 2016 deferred tax charge of $174 million resulting from the change of the tax functional currency for APLNG to U.S. dollar.
- Higher interest and debt expense.
- Lower gain on dispositions, mainly due to the absence of a $368 million after-tax gain on the disposition of certain properties in our Lower 48 segment.

*2015 vs. 2014*

Earnings for ConocoPhillips decreased 175 percent in 2015. The decrease was mainly due to lower commodity prices.

In addition, earnings were negatively impacted by:

- Higher proved property and equity investment impairments, including a $1.5 billion before- and after-tax impairment of our equity investment in APLNG.
- Higher exploration expenses. Exploration expenses increased mainly as a result of higher unproved property impairments, dry hole costs and other exploration expenses. The increase included after-tax unproved property impairments of $368 million for our Alaska Chukchi Sea leasehold and capitalized interest, $310 million for our Angola Block 36 and 37 PSCs, $154 million for multiple Gulf of Mexico leases, and $100 million for various Gila Prospect blocks. Additional after-tax dry hole costs and other expenses resulted from a $185 million charge for several properties in Canada, $140 million for two dry holes in Angola, $111 million for a dry hole in the Gila Prospect in deepwater Gulf of Mexico, and $246 million related to the termination of our drilling contract with Ensco.
- Higher DD&A, mainly from increased production and commodity price-driven reserve revisions.
- Higher restructuring charges and pension settlement expense.

These reductions to earnings were partly offset by higher sales volumes, lower production taxes due to reduced commodity prices, lower operating expenses, a $555 million net deferred tax benefit resulting from a change in the U.K. tax rate in the first quarter of 2015, the absence of a $540 million after-tax loss resulting from the Freeport LNG termination agreement, gain on sale of assets, and higher licensing revenue.

**Income Statement Analysis**

*2016 vs. 2015*

Sales and other operating revenues decreased 20 percent in 2016, mainly as a result of lower prices across all commodities. Additionally, sales and other operating revenues decreased due to lower natural gas, crude oil and natural gas liquids sales volumes, mainly from dispositions and field decline, partly offset by increased bitumen sales volumes.

Equity in earnings of affiliates decreased 92 percent in 2016. The decrease was primarily due to lower commodity prices, increased DD&A mainly from Trains 1 and 2 being placed in service at APLNG, and a 2016 deferred tax charge of $174 million resulting from a tax functional currency change. The decrease in earnings was partly offset by higher sales volumes at APLNG and FCCL Partnership, as well as lower production taxes at Qatar Liquefied Gas Company Limited (3) (QG3).

Gain on dispositions decreased 39 percent in 2016. The decrease resulted from the absence of a $583 million before-tax gain in 2015 from the sales of producing properties in East Texas and North Louisiana, South Texas, and a certain pipeline and gathering assets in South Texas, as well as a $26 million before-tax loss on the sale of our interest in the Block B PSC in Indonesia in 2016. The decrease was partly offset by the absence of a $149 million before-tax loss on the disposition of non-core assets in western Canada in the fourth quarter of 2015; and gains on the 2016 dispositions of ConocoPhillips Senegal B.V., the entity that held our interests in three exploration blocks offshore Senegal, the Alaska Beluga River Unit natural gas field, and non-core assets in the Lower 48. For additional information on gains on dispositions, see Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

Other income increased 104 percent in 2016, mainly due to a gain of $88 million from our receipt of mineral properties and active leases from the Greater Northern Iron Ore Properties Trust in the fourth quarter of 2016. Other income was further increased $76 million before-tax for a damage claim settlement in our Lower 48 segment.

Purchased commodities decreased 20 percent in 2016, mainly due to lower natural gas prices.

Production and operating expenses decreased 19 percent in 2016, mainly due to lower operating expense activity, reduced headcount and dispositions of non-core assets, as well as favorable foreign currency impacts.

Selling, general and administrative (SG&A) expenses decreased 24 percent in 2016, primarily due to reduced restructuring expenses, lower headcount and reduced activity. The decrease was partly offset by increases from market impacts on certain compensation programs.

Exploration expenses decreased 54 percent in 2016, primarily as a result of lower leasehold impairment expense, dry hole costs, and other exploration expenses.

Leasehold impairment expense was reduced, mainly due to the absence of 2015 before-tax charges of $575 million for our Chukchi Sea leasehold and capitalized interest; $493 million for Angola Blocks 36 and 37; and $447 million for certain Gulf of Mexico leases, partly offset by 2016 impairments of our Melmar, Gibson, Tiber and other Gulf of Mexico leaseholds.

Dry hole costs were reduced due to the absence of before-tax charges of $1,141 million in 2015, mainly from wells in deepwater Gulf of Mexico, Horn River and Northwest Territories in Canada, Angola Blocks 36 and 37, and Malaysia. The reduction in costs was partly offset by before-tax charges in 2016, including $434 million from several wells in deepwater Gulf of Mexico and $256 million for two wells in Nova Scotia.

Other exploration expenses were reduced mainly due to the absence of a $335 million before-tax charge in 2015 related to the termination of our Ensco Gulf of Mexico deepwater drillship contract, partly offset by before-tax rig cancellation charges and third-party costs of $146 million for our final Gulf of Mexico deepwater drillship contract in 2016.

For additional information on leasehold impairments and other exploration expenses, see Note 8—Suspended Wells and Other Exploration Expenses, and Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Impairments decreased 94 percent in 2016. For additional information, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes decreased 18 percent in 2016, primarily as a result of lower production taxes, mainly in our Alaska and Lower 48 segments, given reduced commodity prices and the absence of the impact of a transportation cost ruling by the Federal Energy Regulatory Commission in the fourth quarter of 2015 in Alaska. Taxes other than income taxes were additionally decreased due to lower property taxes in 2016 in our Alaska and Lower 48 segments.

Interest and debt expense increased 35 percent in 2016, primarily due to lower capitalized interest on projects and increased debt.

See Note 19—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax provision (benefit) and effective tax rate.

*2015 vs. 2014*

Sales and other operating revenues decreased 44 percent in 2015, mainly as a result of lower prices across all commodities. Lower prices were partly offset by higher crude oil and LNG sales volumes.

Equity in earnings of affiliates decreased 74 percent in 2015. The decrease was primarily due to lower earnings from FCCL and QG3, given lower commodity prices, partly offset by higher volumes and lower operational costs.

Gain on dispositions increased by $493 million in 2015. The increase resulted from a $583 million gain from the sales of producing properties in East Texas and North Louisiana, South Texas, and a certain pipeline and gathering assets in South Texas. Gains realized were partly offset by a net loss from the disposition of non-core assets in western Canada. For additional information on gains on dispositions, see Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

Other income decreased 66 percent in 2015, mainly due to the absence of 2014 income related to the resolution of a contingent liability in the Other International segment and a legal arbitration settlement in Asia Pacific and Middle East.

Purchased commodities decreased 44 percent in 2015, largely as a result of lower natural gas prices and the absence of a $130 million loss in the Lower 48 related to transportation and storage capacity agreements recognized in 2014.

Production and operating expenses decreased 21 percent in 2015, largely due to lower operating expense activity, including reduced turnarounds at our Bayu-Undan Field and Darwin LNG facility, favorable foreign exchange-related impacts, and the absence of an $849 million charge resulting from the Freeport LNG termination agreement in 2014. The decrease in expense was partially offset by restructuring expenses of $206 million in 2015.

SG&A expenses increased 30 percent in 2015, primarily due to $407 million in restructuring and pension settlement expenses, partially offset by lower staff and compensation plan costs.

Exploration expenses increased 105 percent in 2015, mainly as a result of higher unproved property impairments, primarily in Alaska, Angola and the Lower 48. Higher dry hole and other exploration costs, including a $253 million before-tax expense for wells charged to dry hole in Canada, a $383 million expense related to the termination of our Gulf of Mexico deepwater drillship contract, and a $176 million charge for two wells charged to dry hole in the Gila Prospect in the deepwater Gulf of Mexico, also contributed to the increase in exploration expenses. For additional information on leasehold impairments and other exploration expenses, see Note 8—Suspended Wells and Other Exploration Expenses and Note 9—Impairments, in the Notes to Consolidated Financial Statements.

DD&A increased 9 percent in 2015. The increase was mainly associated with higher production volumes in the Lower 48 and Asia Pacific and Middle East and commodity price-related reserve revisions, partly offset by reserve additions in the Lower 48.

Impairments increased 162 percent in 2015. For additional information, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes decreased 57 percent in 2015, mainly due to lower production taxes from reduced commodity prices in the Lower 48, Alaska and Asia Pacific and Middle East.

Interest and debt expense increased 42 percent in 2015, primarily due to lower capitalized interest on projects and increased average debt levels in 2015.

See Note 19—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax provision (benefit) and effective tax rate.

**Summary Operating Statistics**

| | | **2016** | 2015 | 2014 |
|---|---|---|---|---|
| **Average Net Production** | | | | |
| Crude oil (MBD)* | | **598** | 605 | 595 |
| Natural gas liquids (MBD) | | **145** | 156 | 159 |
| Bitumen (MBD) | | **183** | 151 | 129 |
| Natural gas (MMCFD)** | | **3,857** | 4,060 | 3,943 |
| **Total Production** (MBOED)*** | | **1,569** | 1,589 | 1,540 |
| | | Dollars Per Unit | | |
| **Average Sales Prices** | | | | |
| Crude oil (per barrel) | $ | **40.86** | 48.26 | 92.80 |
| Natural gas liquids (per barrel) | | **16.68** | 17.79 | 38.99 |
| Bitumen (per barrel) | | **15.27** | 18.72 | 55.13 |
| Natural gas (per thousand cubic feet) | | **3.00** | 3.96 | 6.57 |
| | | Millions of Dollars | | |
| **Worldwide Exploration Expenses** | | | | |
| General and administrative; geological and geophysical, lease rental, and other | $ | **731** | 1,127 | 879 |
| Leasehold impairment | | **466** | 1,924 | 562 |
| Dry holes | | **718** | 1,141 | 604 |
| | $ | **1,915** | 4,192 | 2,045 |

*Excludes discontinued operations.*
**Thousands of barrels per day.*
***Millions of cubic feet per day. Represents quantities available for sale and excludes gas equivalent of natural gas liquids included above.*
****Thousands of barrels of oil equivalent per day.*

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2016, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

Total production, including Libya, of 1,569 MBOED decreased 1 percent in 2016 compared with 2015. The decrease in total average production primarily resulted from normal field decline and the loss of 72 MBOED mainly attributable to the 2015 dispositions of several non-core assets in the Lower 48, western Canada and the sale of our interest in the Polar Lights Company in Russia. The decrease in production was partly offset by additional production from major developments, including tight oil plays in the Lower 48; APLNG in Australia; the Western North Slope in Alaska; the Kebabangan gas field in Malaysia; and the Greater Ekofisk Area in Norway. Improved drilling and well performance in Canada, Norway, the Lower 48, and China, as well as lower unplanned downtime in the Lower 48 also partly offset the decrease in production. Adjusted for downtime and dispositions of 66 MBOED, our production, excluding Libya, increased by 44 MBOED, or 3 percent, compared with 2015. Assets sold in 2016 produced 27 MBOED and 36 MBOED in 2016 and 2015, respectively.

In 2015, average production from continuing operations, including Libya, increased 3 percent compared with 2014, while average liquids production increased 4 percent. The increase in total average production in 2015 primarily resulted from additional production from major developments, including tight oil plays in the Lower 48; Gumusut in Malaysia; APLNG in Australia; Greater Britannia projects and the J-Area in the U.K.; and the ramp-up of Foster Creek Phase F in Canada. Improved well performance, mostly in the Lower 48, western Canada and Norway, and lower turnaround activity also contributed to higher production in 2015. These increases were largely offset by normal field decline. Adjusted for downtime and dispositions of 13 MBOED, our production from continuing operations, excluding Libya, increased by 70 MBOED, or 5 percent, compared with 2014. Full-year 2015 production from assets sold or under agreement was 64 MBOED.

**Alaska**

| | | **2016** | 2015 | 2014 |
|---|---|---|---|---|
| **Income from Continuing Operations** (millions of dollars) | $ | **319** | 4 | 2,041 |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **163** | 158 | 162 |
| Natural gas liquids (MBD) | | **12** | 13 | 13 |
| Natural gas (MMCFD) | | **25** | 42 | 49 |
| **Total Production** (MBOED) | | **179** | 178 | 183 |
| **Average Sales Prices** | | | | |
| Crude oil (per barrel) | $ | **41.93** | 51.61 | 97.68 |
| Natural gas (per thousand cubic feet) | | **5.22** | 4.33 | 5.42 |

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids, natural gas and LNG. In 2016, Alaska contributed 19 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

*2016 vs. 2015*

Alaska reported earnings of $319 million in 2016, compared with earnings of $4 million in 2015. The increase in earnings was mainly due to:

- Lower exploration expenses, primarily due to the absence of the 2015 impairment charge for our Chukchi Sea leasehold and capitalized interest. For additional information on our impairments, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.
- Reduced production and operating expense, mainly from lower maintenance costs and general and administrative expenses.
- Enhanced oil recovery tax credits.
- Higher crude oil sales volumes, partly offset by the absence of LNG sales volumes.
- A $57 million after-tax impact for the recognition of state deferred tax assets.
- A $36 million after-tax gain on the sale of our interest in the Alaska Beluga River Unit natural gas field.

The increase in earnings was partly offset by lower crude oil prices and higher DD&A expense, mainly due to capital additions.

Average production increased 1 percent in 2016 compared with 2015, primarily due to new production from the Alpine CD5 drill site and strong well performance in the Greater Prudhoe Area. The production increase was partly offset by normal field decline.

*2015 vs. 2014*

Alaska reported earnings of $4 million in 2015, compared with earnings of $2,041 million in 2014, mainly due to lower commodity prices and a $368 million after-tax charge in the fourth quarter of 2015 for the impairment of our Chukchi Sea leasehold and capitalized interest. The earnings decrease was partly offset by reduced production taxes resulting from lower commodity prices.

Average production decreased 3 percent in 2015 compared with 2014, primarily due to normal field decline, partly offset by lower planned downtime activity and new production from the Western North Slope, Greater Prudhoe and Greater Kuparuk areas.

**Lower 48**

| | | 2016 | 2015 | 2014 |
|---|---|---|---|---|
| **Loss from Continuing Operations** (millions of dollars) | $ | **(2,257)** | (1,932) | (22) |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **195** | 206 | 188 |
| Natural gas liquids (MBD) | | **88** | 94 | 97 |
| Natural gas (MMCFD) | | **1,219** | 1,472 | 1,491 |
| **Total Production** (MBOED) | | **486** | 545 | 533 |
| **Average Sales Prices** | | | | |
| Crude oil (per barrel) | $ | **37.49** | 42.62 | 84.18 |
| Natural gas liquids (per barrel) | | **14.34** | 14.01 | 30.74 |
| Natural gas (per thousand cubic feet) | | **2.20** | 2.43 | 4.29 |

The Lower 48 segment consists of operations located in the U.S. Lower 48 states and exploration activities in the Gulf of Mexico. During 2016, the Lower 48 contributed 30 percent of our worldwide liquids production and 32 percent of our natural gas production.

*2016 vs. 2015*

Lower 48 reported a loss of $2,257 million after-tax in 2016, compared with a loss of $1,932 million after-tax in 2015. The increase in losses was primarily due to:

- The absence of a $368 million after-tax gain on the disposition of certain properties in South Texas, East Texas and North Louisiana.
- Lower crude oil and natural gas prices.
- Lower sales volumes across all commodities due to dispositions and field decline.
- Higher proved property impairments, including a $49 million after-tax impairment associated with changes to development plans for Eagle Ford infrastructure.

The increase in losses was partly offset by:

- Lower production and operating expenses, mainly due to reduced activity and cost efficiencies.
- Lower exploration expenses, mainly due to:
    - Reduced other exploration costs, mainly due to the absence of a $216 million after-tax charge related to the termination of our Gulf of Mexico deepwater drillship contract with Ensco in 2015, partly offset by 2016 rig cancellation and related third party costs of $95 million after-tax for our final Gulf of Mexico deepwater drillship contract.
    - Lower general and administrative, and geological and geophysical expenses.
    - Lower leasehold impairment expense, including the absence of 2015 after-tax charges of $154 million for certain leases in the Gulf of Mexico and $100 million for various blocks in the Gila Prospect. The decrease in leasehold impairment was partly offset by 2016 after-tax charges of $132 million for our Gibson and Tiber leaseholds and $62 million for the Melmar Prospect, all in the Gulf of Mexico.

- Lower exploration expenses were partly offset by slightly increased dry hole costs in 2016, including after-tax charges in deepwater Gulf of Mexico of $162 million for our Gibson and Tiber wells and $83 million associated with our Melmar well. Dry hole costs in 2016 were partly offset by the absence of a $111 million after-tax charge in 2015 associated with two wells in the Gila Prospect in the deepwater Gulf of Mexico.

- An $88 million gain associated with our receipt of Greater Northern Iron Ore Properties Trust assets in the fourth quarter of 2016.
- A $48 million after-tax benefit from a damage claim settlement.
- A $38 million after-tax gain from the disposition of non-core assets and lease exchanges.
- Lower DD&A, mainly due to 2016 reserve additions and reduced volumes, partly offset by price-related reserve revisions.

Our average realized prices in the Lower 48 have historically correlated with WTI prices; however, beginning in the second half of 2013, our Lower 48 crude differential versus WTI began to widen. Our 2016 average realized crude oil price of $37.49 per barrel was 13 percent less than WTI of $43.20 per barrel. The differential is driven primarily by local market dynamics in the Gulf Coast, Bakken and the Permian Basin, and may remain relatively wide in the near term.

Total average production decreased 11 percent in 2016 compared with 2015. The decrease was mainly attributable to normal field decline and the 2015 disposition of non-core properties in East Texas and North Louisiana, as well as South Texas. The reduction was partly offset by new production and well performance, primarily from Eagle Ford, Bakken and the Permian Basin, as well as lower unplanned downtime.

*2015 vs. 2014*

Lower 48 reported a loss of $1,932 million after-tax in 2015, compared with a loss of $22 million after-tax in 2014. The decrease in earnings was primarily due to:

- Lower crude oil, natural gas and natural gas liquids prices.
- Higher DD&A, mostly due to increased crude oil production.
- Higher exploration expenses, mainly due to:

    - Increased impairment expense in 2015, including after-tax charges of $154 million for certain leases in the Gulf of Mexico and $100 million for various blocks in the Gila Prospect, where we ceased further activity.
    - A $246 million after-tax charge to exploration expense related to the termination of our Gulf of Mexico deepwater drillship contract with Ensco.
    - Higher dry hole costs, including $111 million after-tax, associated with two wells in the Gila Prospect in the deepwater Gulf of Mexico.

These decreases were partly offset by the absence of a $545 million after-tax charge resulting from the Freeport LNG termination agreement in 2014; a $368 million after-tax gain on the disposition of certain properties in South Texas, East Texas and North Louisiana; higher volumes; lower production taxes; and the absence of a $151 million after-tax impairment charge resulting from reduced volume forecasts on proved properties and the associated undeveloped leasehold costs.

Total average production increased 2 percent in 2015 compared with 2014, while average crude oil production increased 10 percent across the same period. The increase was mainly attributable to new production, primarily from Eagle Ford, Bakken and the Permian Basin, partially offset by normal field decline.

## Canada

| | | 2016 | 2015 | 2014 |
|---|---|---|---|---|
| **Income (Loss) from Continuing Operations** (millions of dollars) | $ | **(935)** | (1,044) | 940 |
| | | | | |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **7** | 12 | 13 |
| Natural gas liquids (MBD) | | **23** | 26 | 23 |
| Bitumen (MBD) | | | | |
| Consolidated operations | | **35** | 13 | 12 |
| Equity affiliates | | **148** | 138 | 117 |
| Total bitumen | | **183** | 151 | 129 |
| | | | | |
| Natural gas (MMCFD) | | **524** | 715 | 711 |
| | | | | |
| **Total Production** (MBOED) | | **300** | 308 | 284 |
| | | | | |
| **Average Sales Prices** | | | | |
| Crude oil (per barrel) | $ | **35.25** | 39.52 | 77.87 |
| Natural gas liquids (per barrel) | | **14.82** | 17.02 | 46.23 |
| Bitumen (dollars per barrel) | | | | |
| Consolidated operations | | **12.91** | 20.13 | 60.03 |
| Equity affiliates | | **15.80** | 18.58 | 54.62 |
| Total bitumen | | **15.27** | 18.72 | 55.13 |
| Natural gas (per thousand cubic feet) | | **1.49** | 1.91 | 4.13 |

Our Canadian operations mainly consist of natural gas fields in western Canada and oil sands developments in the Athabasca Region of northeastern Alberta. In 2016, Canada contributed 23 percent of our worldwide liquids production and 14 percent of our worldwide natural gas production.

*2016 vs. 2015*

Canada operations reported a loss of $935 million in 2016, a decrease in loss of $109 million compared with 2015. The decrease in loss was primarily due to:

- The absence of a $136 million impact of a 2 percent increase in Alberta corporate tax rates on deferred taxes in 2015.
- Lower production and operating expenses, mainly due to reduced headcount and the disposition of non-core assets in western Canada.
- Lower exploration expenses, mainly due to:
    - Reduced leasehold impairment expense, including the absence of an impairment charge for undeveloped leasehold in the Duvernay, Thornbury, Saleski and Crow Lake areas. The reduction in leasehold impairment expense was partly offset by a $23 million after-tax charge in the fourth quarter of 2016 primarily due to decisions to discontinue further testing on undeveloped leaseholds.
    - Lower general and administrative, and geological and geophysical expenses.
    - Lower dry hole costs, mainly due to the absence of 2015 charges associated with our Horn River, Northwest Territories, Thornbury and Saleski properties, partly offset by dry hole costs in 2016, including total after-tax charges in offshore Nova Scotia of $187 million for our Cheshire and Monterey Jack wells.

- Higher gains on dispositions, including the absence of a $103 million net after-tax loss on the disposition of non-core assets in western Canada in 2015.

The decrease in loss was partly offset by lower commodity prices; higher DD&A expense, mainly from price-related reserve revisions; and a $42 million after-tax impairment charge related to certain developed properties in central Alberta, which were classified as held for sale, being written down to fair value less costs to sell.

Total average production decreased 3 percent in 2016 compared with 2015, while bitumen production increased 21 percent over the same periods. The decrease in total production was mainly attributable to the disposition of non-core assets in western Canada and normal field decline. The production decrease was partly offset by strong well performance in western Canada, Surmont and FCCL. Surmont has fully recovered from the forest fire impacts.

*2015 vs. 2014*

Canada operations reported a loss of $1,044 million in 2015, a reduction in earnings of $1,984 million compared with 2014. The decrease in earnings was primarily due to:

- Lower bitumen and natural gas prices.
- Higher exploration expenses, mainly due to:
    - Higher dry hole costs, including an after-tax charge of $185 million associated with our Horn River, Northwest Territories, Thornbury and Saleski properties.
    - An after-tax impairment charge of $75 million for undeveloped leaseholds in the Duvernay, Thornbury, Saleski and Crow Lake areas.
- A 2 percent increase in Alberta corporate tax rates on deferred taxes.
- A $103 million net after-tax loss realized on the disposition of non-core assets in western Canada.

The earnings decrease was partly offset by higher bitumen production volumes; lower operating expenses and DD&A, both primarily from favorable foreign currency impacts; and the absence of the $109 million after-tax impairment of undeveloped leasehold costs associated with the offshore Amauligak discovery, Arctic Islands and other Beaufort properties in 2014.

Total average production increased 8 percent in 2015 compared with 2014, while bitumen production increased 17 percent over the same periods. The increases in total production were mainly attributable to strong well performance in western Canada, lower royalty impacts, strong plant performance at Foster Creek and Christina Lake and the continued ramp-up of production from Foster Creek Phase F. These increases were partly offset by normal field decline and increased unplanned downtime, including the precautionary shut down of Foster Creek for nearby forest fires in the second quarter of 2015.

**Europe and North Africa**

| | | 2016 | 2015 | 2014 |
|---|---|---|---|---|
| **Income from Continuing Operations** (millions of dollars) | $ | **394** | 409 | 814 |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **122** | 120 | 134 |
| Natural gas liquids (MBD) | | **7** | 7 | 8 |
| Natural gas (MMCFD) | | **460** | 476 | 464 |
| **Total Production** (MBOED) | | **205** | 207 | 219 |
| **Average Sales Prices** | | | | |
| Crude oil (dollars per barrel) | $ | **43.66** | 52.75 | 98.98 |
| Natural gas liquids (per barrel) | | **22.62** | 27.56 | 52.65 |
| Natural gas (per thousand cubic feet) | | **4.71** | 7.14 | 9.28 |

The Europe and North Africa segment consists of operations principally located in the Norwegian and U.K. sectors of the North Sea, the Norwegian Sea, and Libya. In 2016, our Europe and North Africa operations contributed 14 percent of our worldwide liquids production and 12 percent of our natural gas production.

*2016 vs. 2015*

Earnings for Europe and North Africa operations of $394 million decreased 4 percent in 2016. The decrease in earnings was primarily due to the absence of a $555 million net deferred tax benefit as a result of a change in the U.K. tax rate, effective at the beginning of 2015; lower crude oil and natural gas prices; lower sales volumes; and the absence of a 2015 after-tax gain of $49 million on the sale of our 1.9 percent interest in Norwegian Continental Shelf Gas Transportation (Gassled).

The decrease in earnings was partly offset by:

- Lower property impairments, including the absence of 2015 after-tax charges of $317 million in the U.K. due to lower crude oil and natural gas prices, and a $180 million credit to impairment in 2016 due to decreased asset retirement obligation estimates on fields that are nearing the end of life and were impaired in prior years. The reduction in property impairments was partly offset by a $59 million after-tax charge associated with our Calder Field and Rivers terminal in the U.K. For additional information on our impairments, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.
- Lower DD&A expense in the U.K. driven by reduced rate, as a result of completed depreciation on the Brodgar H3 tie-back well in 2015, and lower volumes.
- A $161 million net deferred tax benefit resulting from a reduction in the U.K. tax rate, which was enacted in September 2016 and effective January 1, 2016.
- Reduced operating expenses across the segment.

Average production decreased 1 percent in 2016, compared with 2015. The decrease in production was mainly due to normal field decline, partly offset by improved drilling and well performance in Norway and new production from the Greater Ekofisk and Greater Britannia areas. Libya production remained largely shut in, as the Es Sider crude oil export terminal closure continued throughout the third quarter of 2016. Production resumed in Libya in October 2016, with three crude liftings from Es Sider in January 2017. We expect a gradual ramp-up in activity.

*2015 vs. 2014*

Earnings for Europe and North Africa operations decreased 50 percent in 2015. The decrease in earnings was primarily due to lower crude oil and natural gas prices. Earnings further decreased due to higher property impairments in the U.K., given lower natural gas prices and increases to asset retirement obligations. The earnings decrease was partly offset by a $555 million net deferred tax benefit as a result of a change in the U.K. tax rate, effective at the beginning of 2015, and an after-tax gain of $49 million on the sale of our 1.9 percent interest in Norwegian Continental Shelf Gas Transportation (Gassled).

For additional information on the impairments, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Average production decreased 5 percent in 2015, compared with 2014. The decrease in production was mostly due to normal field decline and lower volumes from Libya, partly offset by the new production from the Greater Britannia Area, the J-Area and the Greater Ekofisk Area, as well as improved well performance in Norway.

The Es Sider Terminal in Libya remained shut in throughout 2015 as a result of civil unrest.

**Asia Pacific and Middle East**

| | | **2016** | 2015 | 2014 |
|---|---|---|---|---|
| **Income (Loss) from Continuing Operations** (millions of dollars) | $ | **265** | (406) | 3,008 |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | | | |
| Consolidated operations | | **97** | 91 | 79 |
| Equity affiliates | | **14** | 14 | 15 |
| Total crude oil | | **111** | 105 | 94 |
| Natural gas liquids (MBD) | | | | |
| Consolidated operations | | **7** | 9 | 10 |
| Equity affiliates | | **8** | 7 | 8 |
| Total natural gas liquids | | **15** | 16 | 18 |
| Natural gas (MMCFD) | | | | |
| Consolidated operations | | **730** | 717 | 723 |
| Equity affiliates | | **899** | 638 | 505 |
| Total natural gas | | **1,629** | 1,355 | 1,228 |
| **Total Production** (MBOED) | | **399** | 347 | 317 |
| **Average Sales Prices** | | | | |
| Crude oil (dollars per barrel) | | | | |
| Consolidated operations | $ | **42.23** | 49.70 | 95.32 |
| Equity affiliates | | **44.11** | 53.12 | 99.01 |
| Total crude oil | | **42.47** | 50.16 | 95.92 |
| Natural gas liquids (dollars per barrel) | | | | |
| Consolidated operations | | **29.00** | 37.78 | 69.36 |
| Equity affiliates | | **31.13** | 35.79 | 67.20 |
| Total natural gas liquids | | **30.11** | 36.88 | 68.46 |
| Natural gas (dollars per thousand cubic feet) | | | | |
| Consolidated operations | | **4.31** | 6.23 | 9.80 |
| Equity affiliates | | **2.97** | 4.83 | 9.79 |
| Total natural gas | | **3.57** | 5.58 | 9.80 |

The Asia Pacific and Middle East segment has operations in China, Indonesia, Malaysia, Australia, Timor-Leste and Qatar, as well as exploration activities in Brunei. During 2016, Asia Pacific and Middle East contributed 14 percent of our worldwide liquids production and 42 percent of our natural gas production.

*2016 vs. 2015*

Asia Pacific and Middle East reported earnings of $265 million in 2016, compared with a loss of $406 million in 2015. The earnings increase was mainly due to:

- The absence of a $1,502 million before- and after-tax charge for the impairment of our APLNG investment in 2015. For additional information on our APLNG impairment, see the "APLNG" section of Note 7—Investments, Loans and Long-Term Receivables in the Notes to Consolidated Financial Statements.
- Higher LNG sales volumes.

- Lower production taxes.
- Reduced feedstock costs at Darwin LNG.
- Lower operating expenses, mainly due to lower general and administrative spend, maintenance costs and transportation expenses across the segment.
- Lower exploration expenses, mainly due to lower dry hole costs, as well as the absence of a $41 million after-tax charge in 2015 for the impairment of our relinquished Palangkaraya PSC, and reduced exploration general and administrative expense.

The earnings increase was partly offset by lower prices across all commodities; lower equity earnings from APLNG, mainly as a result of higher DD&A expense from APLNG Trains 1 and 2 coming online; and a third-quarter 2016 deferred tax charge of $174 million resulting from APLNG's tax functional currency change.

Average production increased 15 percent in 2016, compared with 2015. The production increase in 2016 was mainly attributable to new production from the ramp-up of APLNG in Australia and the Kebabangan gas field in Malaysia, improved drilling and well performance in China and Malaysia, and increased recoveries from production sharing contracts in Indonesia. The production increase was partially offset by normal field decline across the segment.

*2015 vs. 2014*

Asia Pacific and Middle East reported a loss of $406 million in 2015, compared with income of $3,008 million in 2014. The decrease in earnings was mainly due to lower prices across all commodities. Earnings in 2015 were further decreased by a $1,502 million before- and after-tax charge for the impairment of our APLNG investment, higher DD&A expense from increased volumes, primarily in Malaysia, and a $41 million after-tax charge for the impairment of our relinquished Palangkaraya PSC. The earnings decrease was partially offset by lower production taxes, increased volumes, as well as lower feedstock costs and reduced turnarounds at our Bayu-Undan Field and Darwin LNG facility.

Average production increased 9 percent in 2015, compared with 2014. The production increase was mainly attributable to new production from Gumusut, in Malaysia, which came online in the fourth quarter of 2014; the ramp-up of APLNG production due to additional gas processing facilities online; and infill drilling in China. Production increases were partly offset by normal field decline.

**Other International**

| | | **2016** | 2015 | 2014 |
|---|---|---|---|---|
| **Loss from Continuing Operations** (millions of dollars) | $ | **(16)** | (593) | (100) |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | | | |
| Equity affiliates | | **-** | 4 | 4 |
| **Total Production** (MBOED) | | **-** | 4 | 4 |
| **Average Sales Prices** | | | | |
| Crude oil (dollars per barrel) | | | | |
| Equity affiliates | | **-** | 37.21 | 64.14 |

The Other International segment includes exploration activities in Colombia and Chile.

*2016 vs. 2015*

Other International operations reported a loss of $16 million in 2016, compared with a loss of $593 million in 2015. The decrease in losses was primarily due to the absence of after-tax charges in 2015 of $235 million, $75 million and $32 million net for property impairments on our Angola Block 36, Angola Block 37 and Poland leasehold, respectively. Additionally, losses decreased due to the absence of the 2015 after-tax dry hole expenses offshore Angola of $81 million for the Omosi-1 well and $59 million for the Vali-1 well, combined with a $138 million gain on the disposition of ConocoPhillips Senegal B.V., the entity that held our interest in three exploration blocks offshore Senegal.

*2015 vs. 2014*

Other International operations reported a loss of $593 million in 2015, compared with a loss of $100 million in 2014. The decrease in earnings was primarily due to after-tax charges of $235 million, $75 million and $32 million net for property impairments on our Angola Block 36, Angola Block 37 and Poland leasehold, respectively. Earnings were also reduced due to increased dry hole expenses for the Omosi-1 and Vali-1 wells offshore Angola and the absence of other income of $154 million after-tax associated with the favorable resolution of a contingent liability. The reduction in earnings was partly offset by the absence of the $136 million after-tax charge in 2014 for the Kamoxi-1 exploration well, located offshore Angola; and a $53 million after-tax gain from the disposition of our interest in the Polar Lights Company.

For additional information on the impairments, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Average production was flat in 2015 compared with 2014.

**Corporate and Other**

| | Millions of Dollars | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| **Income (Loss) from Continuing Operations** | | | |
| Net interest | **$ (980)** | (518) | (502) |
| Corporate general and administrative expenses | **(289)** | (246) | (194) |
| Technology | **50** | 122 | (93) |
| Other | **(110)** | (167) | (85) |
| | **$ (1,329)** | (809) | (874) |

*2016 vs. 2015*

Net interest consists of interest and financing expense, net of interest income and capitalized interest, as well as premiums incurred on the early retirement of debt. Net interest increased 89 percent in 2016 compared with 2015, primarily as a result of the absence of the 2015 impacts from the fair market value of apportioning interest expense in the United States, lower capitalized interest on projects, and increased debt.

Corporate general and administrative expenses increased 17 percent in 2016, mainly due to increases from market impacts on certain compensation programs, partly offset by lower staff expenses.

Technology includes our investment in new technologies or businesses, as well as licensing revenues received. Activities are focused on tight oil reservoirs, heavy oil and oil sands, as well as LNG. Earnings from Technology were $50 million in 2016, compared with $122 million in 2015. The decrease in earnings primarily resulted from lower licensing revenues, partly offset by reduced technology program spend.

The category “Other” includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, and other costs not directly associated with an operating segment. “Other” expenses decreased 34 percent in 2016, mainly due to lower restructuring costs and favorable foreign currency impacts, partly offset by the absence of a 2015 tax benefit.

*2015 vs. 2014*

Net interest increased 3 percent in 2015 compared with 2014, primarily as a result of lower capitalized interest on projects completed or sold and increased debt.  The 2015 net interest expense increase was largely offset by a $148 million net tax benefit for electing the fair market value method of apportioning interest expense in the United States for prior years.

Corporate general and administrative expenses increased 27 percent in 2015, mainly due to $143 million in after-tax pension settlement expense, partially offset by lower staff and compensation plan costs.

Earnings from Technology were $122 million in 2015, compared with a loss of $93 million in 2014.  The increase in earnings primarily resulted from higher licensing revenues.

Other expenses increased by $82 million in 2015, mainly due to $142 million after-tax in restructuring charges and foreign currency translation impacts, partially offset by lower environmental expenses.

## CAPITAL RESOURCES AND LIQUIDITY

### Financial Indicators

| | Millions of Dollars Except as Indicated | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| Net cash provided by continuing operating activities | $ **4,403** | 7,572 | 16,412 |
| Net cash provided by discontinued operations | **-** | - | 157 |
| Cash and cash equivalents | **3,610** | 2,368 | 5,062 |
| Short-term debt | **1,089** | 1,427 | 182 |
| Total debt | **27,275** | 24,880 | 22,565 |
| Total equity | **35,226** | 40,082 | 52,273 |
| Percent of total debt to capital* | **44 %** | 38 | 30 |
| Percent of floating-rate debt to total debt | **9 %** | 7 | 5 |

**Capital includes total debt and total equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources, including cash generated from operating activities. In addition, during 2016 we received $1,286 million in proceeds from asset sales and issued $4,594 million of new debt consisting of a three-year term loan and fixed rate notes. The primary uses of our available cash were $4,869 million to support our ongoing capital expenditures and investments program; $2,251 million to repay debt; $1,253 million to pay dividends on our common stock; and $126 million to repurchase common stock. During 2016, cash and cash equivalents increased by $1,242 million, to $3,610 million.

In addition to cash flows from operating activities and proceeds from asset sales, we rely on our commercial paper and credit facility programs and our shelf registration statement to support our short- and long-term liquidity requirements. We believe current cash balances and cash generated by operations, together with access to external sources of funds as described below in the "Significant Sources of Capital" section, will be sufficient to meet our funding requirements in the near and long term, including our capital spending program, dividend payments and required debt payments.

### Significant Sources of Capital

*Operating Activities*

During 2016, cash provided by operating activities was $4,403 million, a 42 percent decrease from 2015. The decrease was primarily due to lower prices across all commodities. Cash flows from operating activities were positively impacted by the $585 million and $642 million tax refunds received from the Internal Revenue Service during 2016 and 2015, respectively.

While the stability of our cash flows from operating activities benefits from geographic diversity, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, bitumen, natural gas, LNG and natural gas liquids. Prices and margins in our industry have historically been volatile and are driven by market conditions over which we have no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

The level of absolute production volumes, as well as product and location mix, impacts our cash flows. Our 2016 production averaged 1,569 MBOED. Full-year 2017 production is expected to be 1,540 to 1,570 MBOED, which results in flat to 2 percent growth compared with full-year 2016 production, excluding Libya, of 1,540 MBOED when adjusted for 2016 dispositions of 27 MBOED. Production guidance for 2017 excludes Libya and the impact of future dispositions. Future production is subject to numerous uncertainties, including, among others, the volatile crude oil and natural gas price environment, which may impact investment decisions; the effects of price changes on production sharing and variable-royalty contracts; acquisition and disposition of fields; field production decline rates; new technologies; operating efficiencies;

timing of startups and major turnarounds; political instability; weather-related disruptions; and the addition of proved reserves through exploratory success and their timely and cost-effective development. While we actively manage these factors, production levels can cause variability in cash flows, although generally this variability has not been as significant as that caused by commodity prices.

To maintain or grow our production volumes, we must continue to add to our proved reserve base. Our total reserve replacement in 2016 was negative 194 percent. Over the five-year period ended December 31, 2016, our reserve replacement was 35 percent (including 11 percent from consolidated operations) reflecting the impact of lower prices and asset dispositions. The total reserve replacement amount above is based on the sum of our net additions (revisions, improved recovery, purchases, extensions and discoveries, and sales) divided by our production, as shown in our reserve table disclosures. For additional information about our 2017 capital budget, see the "2017 Capital Budget" section within "Capital Resources and Liquidity" and for additional information on proved reserves, including both developed and undeveloped reserves, see the "Oil and Gas Operations" section of this report.

As discussed in the "Critical Accounting Estimates" section, engineering estimates of proved reserves are imprecise; therefore, each year reserves may be revised upward or downward due to the impact of changes in commodity prices or as more technical data becomes available on reservoirs. In 2016 and 2015, revisions decreased reserves, while in 2014, revisions increased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future.

*Investing Activities*
Proceeds from asset sales in 2016 were $1.3 billion, primarily from the sales of ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal; our 40 percent interest in South Natuna Sea Block B in Indonesia; our interest in the Alaska Beluga River Unit natural gas field in the Cook Inlet; and certain mineral and non-mineral fee lands in northeastern Minnesota. This compares with proceeds of $2.0 billion in 2015, primarily from the sales of certain western Canadian properties; producing properties in East Texas and North Louisiana and in South Texas; a certain pipeline and gathering assets in South Texas; and our 50 percent equity method investment in the Russian joint venture, Polar Lights Company. For additional information, see Note 6—Assets Held for Sale or Sold in the Notes to Consolidated Financial Statements, and the Outlook section within Management's Discussion and Analysis.

*Commercial Paper and Credit Facilities*
On March 28, 2016, we reduced our revolving credit facility, expiring in June 2019, from $7.0 billion to $6.75 billion. Our revolving credit facility may be used for direct bank borrowings, the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper programs. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips or any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the United States. The agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

Our primary funding source for short-term working capital needs is the ConocoPhillips $6.25 billion commercial paper program. Commercial paper maturities are generally limited to 90 days. We also have the ConocoPhillips Qatar Funding Ltd. $500 million commercial paper program, which is used to fund commitments relating to QG3. At both December 31, 2016 and 2015, we had no direct borrowings or letters of credit issued under the revolving credit facility. Under the ConocoPhillips Qatar Funding Ltd. commercial paper programs, no commercial paper was outstanding at December 31, 2016, compared with $803 million at December 31, 2015. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.75 billion in borrowing capacity under our revolving credit facility at December 31, 2016.

Due to the significant decline in commodity prices during 2015, and the expectation these prices could remain depressed in the near future, the major ratings agencies conducted a review of the oil and gas industry. As a result of this review, our credit ratings, along with several other companies in the oil and gas industry, were downgraded. In the first quarter of 2016, Moody's Investors Service downgraded our senior long-term debt ratings to "Baa2" from "A2," with a negative outlook and our short-term commercial paper ratings to "Prime 2" from "Prime 1" and Fitch downgraded our long-term debt ratings to "A-" from "A" with a negative outlook and our short-term commercial paper ratings to "F2" from "F1." In the second quarter of 2016, Standard and Poor's downgraded our senior long-term debt ratings to "A-" from "A," with a negative outlook and our short-term commercial paper ratings to "A-2" from "A-1." We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity, in the event of a further downgrade of our credit rating. If our credit rating were downgraded further, it could increase the cost of corporate debt available to us and restrict our access to commercial paper. If our credit rating were to deteriorate to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our revolving credit facility.

Certain of our project-related contracts, commercial contracts and derivative instruments contain provisions requiring us to post collateral. Many of these contracts and instruments permit us to post either cash or letters of credit as collateral. At December 31, 2016 and December 31, 2015, we had direct bank letters of credit of $304 million and $340 million, respectively, which secured performance obligations related to various purchase commitments incident to the ordinary conduct of business. In the event of further credit ratings downgrades, we may be required to post additional letters of credit.

*Shelf Registration*

We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission (SEC) under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

**Off-Balance Sheet Arrangements**

As part of our normal ongoing business operations and consistent with normal industry practice, we enter into numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements.

For information about guarantees, see Note 12—Guarantees, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

**Capital Requirements**

For information about our capital expenditures and investments, see the "Capital Expenditures" section.

Our debt balance at December 31, 2016, was $27.3 billion, an increase of $2.4 billion from the balance at December 31, 2015, primarily as a result of obtaining a $1.6 billion three-year term loan and the issuance of $3.0 billion in new fixed rate notes, both in March 2016, partly offset by the retirement in October 2016 of the $1,250 million of 5.625% Notes at maturity, the $803 million repayment of outstanding commercial paper, and early repayment of $150 million of our term loan. Our short-term debt balance at December 31, 2016, decreased $338 million compared with December 31, 2015, primarily as a result of the timing of scheduled maturities. For more information, see Note 11—Debt, in the Notes to Consolidated Financial Statements.

To preserve our balance sheet strength and provide financial flexibility through the recent downturn, in the first quarter of 2016, we announced a reduction in the quarterly dividend to $0.25 per share. The dividend was paid March 1, 2016, to stockholders of record at the close of business on February 16, 2016. In July 2016, we announced a dividend of $0.25 per share. The dividend was paid September 1, 2016, to stockholders of record at the close of business on July 25, 2016. In October 2016, we announced a dividend of $0.25 per share. The dividend was paid December 1, 2016, to stockholders of record at the close of business on October 17, 2016.

Additionally, on January 31, 2017, we announced an increase to our quarterly dividend of 6 percent, from $0.25 per share to $0.265 per share. The dividend will be paid March 1, 2017, to stockholders of record at the close of business on February 14, 2017.

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock over the next three years. Repurchase of shares began in November and totaled 2,579,098 shares at a cost of $126 million, through December 31, 2016.

**Contractual Obligations**

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2016:

| | Millions of Dollars | | | | |
|---|---|---|---|---|---|
| | Payments Due by Period | | | | |
| | Total | Up to 1 Year | Years 2–3 | Years 4–5 | After 5 Years |
| Debt obligations (a) | $ 26,423 | 1,005 | 5,542 | 3,689 | 16,187 |
| Capital lease obligations (b) | 852 | 84 | 136 | 139 | 493 |
| Total debt | 27,275 | 1,089 | 5,678 | 3,828 | 16,680 |
| Interest on debt and other obligations | 15,765 | 1,318 | 2,371 | 1,964 | 10,112 |
| Operating lease obligations (c) | 1,626 | 277 | 410 | 504 | 435 |
| Purchase obligations (d) | 22,791 | 15,581 | 2,259 | 1,304 | 3,647 |
| Other long-term liabilities | | | | | |
| Pension and postretirement benefit contributions (e) | 1,628 | 430 | 635 | 563 | - |
| Asset retirement obligations (f) | 8,405 | 202 | 546 | 697 | 6,960 |
| Accrued environmental costs (g) | 247 | 25 | 46 | 42 | 134 |
| Unrecognized tax benefits (h) | 42 | 42 | (h) | (h) | (h) |
| Total | $ 77,779 | 18,964 | 11,945 | 8,902 | 37,968 |

(a) Includes $248 million of net unamortized premiums, discounts and debt issuance costs. See Note 11—Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) Capital lease obligations are presented on a discounted basis.

(c) Operating lease obligations are presented on an undiscounted basis.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms, presented on an undiscounted basis. Does not include purchase commitments for jointly owned fields and facilities where we are not the operator.

The majority of the purchase obligations are market-based contracts related to our commodity business. Product purchase commitments with third parties totaled $4,673 million.

Purchase obligations of $6,232 million are related to agreements to access and utilize the capacity of third-party equipment and facilities, including pipelines and LNG and product terminals, to transport, process, treat and store commodities. The remainder is primarily our net share of purchase commitments for materials and services for jointly owned fields and facilities where we are the operator.

(e) Represents contributions to qualified and nonqualified pension and postretirement benefit plans for the years 2017 through 2021. For additional information related to expected benefit payments subsequent to 2021, see Note 18—Employee Benefit Plans, in the Notes to Consolidated Financial Statements.

(f) Represents estimated discounted costs to retire and remove long-lived assets at the end of their operations.

(g) Represents estimated costs for accrued environmental expenditures presented on a discounted basis for costs acquired in various business combinations and an undiscounted basis for all other accrued environmental costs.

(h) Excludes unrecognized tax benefits of $341 million because the ultimate disposition and timing of any payments to be made with regard to such amounts are not reasonably estimable. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

**Capital Expenditures**

| | Millions of Dollars | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| Alaska | $ **883** | 1,352 | 1,564 |
| Lower 48 | **1,262** | 3,765 | 6,054 |
| Canada | **698** | 1,255 | 2,340 |
| Europe and North Africa | **1,020** | 1,573 | 2,540 |
| Asia Pacific and Middle East | **838** | 1,812 | 3,877 |
| Other International | **104** | 173 | 520 |
| Corporate and Other | **64** | 120 | 190 |
| Capital expenditures and investments from continuing operations | **4,869** | 10,050 | 17,085 |
| Discontinued operations in Nigeria | **-** | - | 59 |
| Capital Program | $ **4,869** | 10,050 | 17,144 |

Our capital expenditures and investments from continuing operations for the three-year period ended December 31, 2016, totaled $32 billion. The 2016 expenditures supported key exploration and developments, primarily:

- Oil and natural gas development and exploration activities in the Lower 48, including Eagle Ford, Bakken, and the Permian Basin.
- In Europe, development activities in the Clair Ridge, Greater Ekofisk, Aasta Hansteen, and Greater Britannia areas, and exploration and appraisal activities in the North Sea.
- Alaska activities related to development in the Greater Kuparuk Area, Greater Prudhoe Area and the Western North Slope, and exploration activities in the National Petroleum Reserve-Alaska.
- Major project expenditures associated with the APLNG joint venture in Australia.
- Oil sands development in Canada.
- Exploration and appraisal drilling in deepwater Gulf of Mexico.
- Exploration activities in offshore Nova Scotia and appraisal activities in western Canada.
- Continued development in China, Malaysia and Indonesia, and exploration and appraisal activity in Senegal and Chile.

2017 CAPITAL BUDGET

In 2016, given our view of greater price volatility, we announced a plan for allocating cash across the business which sets annual capital at a level that maintains flat production volumes. Our 2017 capital budget of $5 billion reaffirms this strategy. We have shifted our capital allocation to focus on value-preserving, shorter cycle time and low cost-of-supply unconventional programs in our resource base.

We are planning to allocate approximately:

- 46 percent of our 2017 capital expenditures budget to development drilling programs. These funds will focus predominantly on the Lower 48 unconventionals including the Eagle Ford and Bakken, as well as development drilling in Norway, Alaska and Canada.
- 26 percent of our 2017 capital expenditures budget to major projects. These funds will focus on major projects in Alaska, China, Europe and Malaysia, as well as APLNG in Australia.
- 15 percent of our 2017 capital expenditures budget to maintain base production and corporate expenditures.
- 13 percent of our 2017 capital expenditures budget to exploration and appraisal activity. These funds will primarily target the Permian and Niobrara, Colombia, Chile, Australia and Canada.

For information on proved undeveloped reserves and the associated costs to develop these reserves, see the "Oil and Gas Operations" section.

**Contingencies**

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. With respect to income tax related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. For information on other contingencies, see "Critical Accounting Estimates" and Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

*Legal and Tax Matters*

We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, personal injury, and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required. See Note 19—Income Taxes, in the Notes to Consolidated Financial Statements, for additional information about income tax-related contingencies.

*Environmental*

We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in our industry. The most significant of these environmental laws and regulations include, among others, the:

- U.S. Federal Clean Air Act, which governs air emissions.
- U.S. Federal Clean Water Act, which governs discharges to water bodies.
- European Union Regulation for Registration, Evaluation, Authorization and Restriction of Chemicals (REACH).
- U.S. Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which imposes liability on generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur.
- U.S. Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage and disposal of solid waste.
- U.S. Federal Oil Pollution Act of 1990 (OPA90), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States.
- U.S. Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and response departments.
- U.S. Federal Safe Drinking Water Act, which governs the disposal of wastewater in underground injection wells.
- U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages.
- European Union Trading Directive resulting in European Emissions Trading Scheme.

These laws and their implementing regulations set limits on emissions and, in the case of discharges to water, establish water quality limits. They also, in most cases, require permits in association with new or modified operations. These permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time consuming. In addition, there can be delays associated with notice and comment periods and the agency's processing of the application. Many of the delays associated with the permitting process are beyond the control of the applicant.

Many states and foreign countries where we operate also have, or are developing, similar environmental laws and regulations governing these same types of activities. While similar, in some cases these regulations may impose additional, or more stringent, requirements that can add to the cost and difficulty of marketing or transporting products across state and international borders.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor easily determinable as new standards, such as air emission standards, water quality standards and stricter fuel regulations, continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change, are expected to continue to have an increasing impact on our operations in the United States and in other countries in which we operate. Notable areas of potential impacts include air emission compliance and remediation obligations in the United States and Canada.

An example is the use of hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas otherwise trapped in lower permeability rock formations. A range of local, state, federal or national laws and regulations currently govern hydraulic fracturing operations, with hydraulic fracturing currently prohibited in some jurisdictions. Although hydraulic fracturing has been conducted for many decades, a number of new laws, regulations and permitting requirements are under consideration by the U.S. Environmental Protection Agency (EPA), the U.S. Department of the Interior, and others which could result in increased costs, operating restrictions, operational delays and/or limit the ability to develop oil and natural gas resources. Governmental restrictions on hydraulic fracturing could impact the overall profitability or viability of certain of our oil and natural gas investments. We have adopted operating principles that incorporate established industry standards designed to meet or exceed government requirements. Our practices continually evolve as technology improves and regulations change.

We also are subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations. Such laws and regulations include CERCLA and RCRA and their state equivalents. Longer-term expenditures are subject to considerable uncertainty and may fluctuate significantly.

We occasionally receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2016, there were 14 sites around the United States in which we were identified as a potentially responsible party under CERCLA and comparable state laws.

For most Superfund sites, our potential liability will be significantly less than the total site remediation costs because the percentage of waste attributable to us, versus that attributable to all other potentially responsible parties, is relatively low. Although liability of those potentially responsible is generally joint and several for federal sites and frequently so for state sites, other potentially responsible parties at sites where we are a party typically have had the financial strength to meet their obligations, and where they have not, or where potentially responsible parties could not be located, our share of liability has not increased materially. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or attain a settlement of liability. Actual cleanup costs generally occur after the parties obtain EPA or equivalent state agency approval. There are relatively few sites where we are a major participant, and given the timing and amounts of anticipated expenditures, neither the cost of remediation at those sites nor such costs at all CERCLA sites, in the aggregate, is expected to have a material adverse effect on our competitive or financial condition.

Expensed environmental costs were $435 million in 2016 and are expected to be about $470 million per year in 2017 and 2018. Capitalized environmental costs were $192 million in 2016 and are expected to be about $275 million per year in 2017 and 2018.

Accrued liabilities for remediation activities are not reduced for potential recoveries from insurers or other third parties and are not discounted (except those assumed in a purchase business combination, which we do record on a discounted basis).

Many of these liabilities result from CERCLA, RCRA and similar state or international laws that require us to undertake certain investigative and remedial activities at sites where we conduct, or once conducted, operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites we identified that may require environmental remediation, but which are not currently the subject of CERCLA, RCRA or other agency enforcement activities. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the future, we may incur significant costs under both CERCLA and RCRA.

Remediation activities vary substantially in duration and cost from site to site, depending on the mix of unique site characteristics, evolving remediation technologies, diverse regulatory agencies and enforcement policies, and the presence or absence of potentially liable third parties. Therefore, it is difficult to develop reasonable estimates of future site remediation costs.

At December 31, 2016, our balance sheet included total accrued environmental costs of $247 million, compared with $258 million at December 31, 2015, for remediation activities in the U.S. and Canada. We expect to incur a substantial amount of these expenditures within the next 30 years.

Notwithstanding any of the foregoing, and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent concerns in our operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, we currently do not expect any material adverse effect upon our results of operations or financial position as a result of compliance with current environmental laws and regulations.

*Climate Change*
There has been a broad range of proposed or promulgated state, national and international laws focusing on greenhouse gas (GHG) reduction. These proposed or promulgated laws apply or could apply in countries where we have interests or may have interests in the future. Laws in this field continue to evolve, and while it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation, such laws, if enacted, could have a material impact on our results of operations and financial condition. Examples of legislation or precursors for possible regulation that do or could affect our operations include:

- European Emissions Trading Scheme (ETS), the program through which many of the European Union (EU) member states are implementing the Kyoto Protocol. Our cost of compliance with the EU ETS in 2016 was approximately $1.4 million (net share before-tax).
- The Alberta Specified Gas Emitter regulations require any existing facility with emissions equal to or greater than 100,000 metric tonnes of carbon dioxide or equivalent per year to reduce its net emissions intensity from its baseline. The reduction requirement increased from 12 percent in 2015, to 15 percent in 2016 and will increase again to 20 percent in 2017. We also incur a carbon tax for emissions from fossil fuel combustion in our British Columbia operations. The total cost of compliance with these regulations in 2016 was approximately $8 million.
- The U.S. Supreme Court decision in Massachusetts v. EPA, 549 U.S. 497, 127 S.Ct. 1438 (2007), confirming that the EPA has the authority to regulate carbon dioxide as an "air pollutant" under the Federal Clean Air Act.
- The U.S. EPA's announcement on March 29, 2010 (published as "Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs," 75 Fed. Reg. 17004 (April 2, 2010)), and the EPA's and U.S. Department of Transportation's joint promulgation of a Final Rule on April 1, 2010, that triggers regulation of GHGs under the Clean Air Act, may trigger more climate-based claims for damages, and may result in longer agency review time for development projects.
- The U.S. EPA's announcement on January 14, 2015, outlining a series of steps it plans to take to address methane and smog-forming volatile organic compound emissions from the oil and gas industry. The former U.S. administration established a goal of reducing the 2012 levels in methane emissions from the oil and gas industry by 40 to 45 percent by 2025.
- Carbon taxes in certain jurisdictions. Our cost of compliance with Norwegian carbon tax legislation in 2016 was approximately $28 million (net share before-tax).
- The agreement reached in Paris in December 2015 at the 21st Conference of the Parties to the United Nations Framework on Climate Change, setting out a new process for achieving global emission reductions.

In the United States, some additional form of regulation may be forthcoming in the future at the federal and state levels with respect to GHG emissions. Such regulation could take any of several forms that may result in the creation of additional costs in the form of taxes, the restriction of output, investments of capital to maintain compliance with laws and regulations, or required acquisition or trading of emission allowances. We are working to continuously improve operational and energy efficiency through resource and energy conservation throughout our operations.

Compliance with changes in laws and regulations that create a GHG emission trading scheme or GHG reduction policies could significantly increase our costs, reduce demand for fossil energy derived products, impact the cost and availability of capital and increase our exposure to litigation. Such laws and regulations could also increase demand for less carbon intensive energy sources, including natural gas. The ultimate impact on our financial performance, either positive or negative, will depend on a number of factors, including but not limited to:

- Whether and to what extent legislation or regulation is enacted.
- The timing of the introduction of such legislation or regulation.
- The nature of the legislation (such as a cap and trade system or a tax on emissions) or regulation.
- The price placed on GHG emissions (either by the market or through a tax).
- The GHG reductions required.
- The price and availability of offsets.
- The amount and allocation of allowances.
- Technological and scientific developments leading to new products or services.
- Any potential significant physical effects of climate change (such as increased severe weather events, changes in sea levels and changes in temperature).
- Whether, and the extent to which, increased compliance costs are ultimately reflected in the prices of our products and services.

The company has responded by putting in place a corporate Climate Change Action Plan, together with individual business unit climate change management plans in order to undertake actions in four major areas:

- Equipping the company for a low emission world, for example by integrating GHG forecasting and reporting into company procedures; utilizing GHG pricing in planning economics; developing systems to handle GHG market transactions.
- Reducing GHG emissions—In 2015, the company reduced or avoided GHG emissions by approximately 566,000 metric tonnes by carrying out a range of programs across a number of business units.
- Evaluating business opportunities such as the creation of offsets and allowances, the use of low carbon energy and the development of low carbon technologies.
- Engaging externally—The company is a sponsor of MIT's Joint Program on the Science and Policy of Global Change; constructively engages in the development of climate change legislation and regulation; and discloses our progress and performance through the Carbon Disclosure Project and the Dow Jones Sustainability Index.

The company uses an estimated market cost of GHG emissions in the range of $9 to $43 per tonne depending on the timing and country or region to evaluate future opportunities.

**Other**

We have deferred tax assets related to certain accrued liabilities, loss carryforwards and credit carryforwards. Valuation allowances have been established to reduce these deferred tax assets to an amount that will, more likely than not, be realized. Based on our historical taxable income, our expectations for the future, and available tax-planning strategies, management expects the net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as offsets to the tax consequences of future taxable income.

## NEW ACCOUNTING STANDARDS

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-02, "Leases" (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB Accounting Standards Codification (ASC) Topic 840, "Leases," and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements. While we continue to evaluate the ASU, we expect the adoption of the ASU to have a material impact on our consolidated financial statements and disclosures. For additional information, see Note 25—New Accounting Standards, in the Notes to Consolidated Financial Statements.

## CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. See Note 1—Accounting Policies, in the Notes to Consolidated Financial Statements, for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent there is a reasonable likelihood materially different amounts would have been reported under different conditions, or if different assumptions had been used. These critical accounting estimates are discussed with the Audit and Finance Committee of the Board of Directors at least annually. We believe the following discussions of critical accounting estimates, along with the discussions of contingencies and of deferred tax asset valuation allowances in this report, address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

### Oil and Gas Accounting

Accounting for oil and gas exploratory activity is subject to special accounting rules unique to the oil and gas industry. The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs. However, leasehold acquisition costs and exploratory well costs are capitalized on the balance sheet pending determination of whether proved oil and gas reserves have been discovered on the prospect.

*Property Acquisition Costs*
For individually significant leaseholds, management periodically assesses for impairment based on exploration and drilling efforts to date. For relatively small individual leasehold acquisition costs, management exercises judgment and determines a percentage probability that the prospect ultimately will fail to find proved oil and gas reserves and pools that leasehold information with others in the geographic area. For prospects in areas with limited, or no, previous exploratory drilling, the percentage probability of ultimate failure is normally judged to be quite high. This judgmental percentage is multiplied by the leasehold acquisition cost, and that product is divided by the contractual period of the leasehold to determine a periodic leasehold impairment charge that is reported in exploration expense.

This judgmental probability percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favorable or unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment amortization expense is adjusted prospectively. At year-end 2016, the book value of the pools of property acquisition costs, that individually are relatively small and thus subject to the above-described periodic leasehold impairment calculation, was $404 million and the accumulated impairment reserve was $197 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 69 percent, and the weighted-average amortization period was approximately two years. If that judgmental percentage were to be raised by 5 percent across all calculations, before-tax leasehold impairment expense in 2017 would increase by approximately $5 million. At year-end 2016, the remaining $3,659 million of net capitalized unproved property costs consisted primarily of individually significant leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently being drilled, suspended exploratory wells, and capitalized interest. Of this amount, approximately $2.5 billion is concentrated in nine major development areas, the majority of which are not expected to move to proved properties in 2017. Management periodically assesses individually significant leaseholds for impairment based on the results of exploration and drilling efforts and the outlook for commercialization.

*Exploratory Costs*
For exploratory wells, drilling costs are temporarily capitalized, or "suspended," on the balance sheet, pending a determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort to justify development.

If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. The accounting notion of "sufficient progress" is a judgmental area, but the accounting rules do prohibit continued capitalization of suspended well costs on the expectation future market conditions will improve or new technologies will be found that would make the development economically profitable. Often, the ability to move into the development phase and record proved reserves is dependent on obtaining permits and government or co-venturer approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as we are actively pursuing such approvals and permits, and believe they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once a determination is made the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and reported in exploration expense.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as a dry hole when it determines the potential field does not warrant further investment in the near term. Criteria utilized in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected development costs, ability to apply existing technology to produce the reserves, fiscal terms, regulations or contract negotiations, and our expected return on investment.

At year-end 2016, total suspended well costs were $1,063 million, compared with $1,260 million at year-end 2015. For additional information on suspended wells, including an aging analysis, see Note 8—Suspended Wells and Other Exploration Expenses, in the Notes to Consolidated Financial Statements.

*Proved Reserves*
Engineering estimates of the quantities of proved reserves are inherently imprecise and represent only approximate amounts because of the judgments involved in developing such information. Reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processing yield factors, installed plant operating capacity and approved operating limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons.

Despite the inherent imprecision in these engineering estimates, accounting rules require disclosure of "proved" reserve estimates due to the importance of these estimates to better understand the perceived value and future cash flows of a company's operations. There are several authoritative guidelines regarding the engineering criteria that must be met before estimated reserves can be designated as "proved." Our geosciences and reservoir engineering organization has policies and procedures in place consistent with these authoritative guidelines. We have trained and experienced internal engineering personnel who estimate our proved reserves held by consolidated companies, as well as our share of equity affiliates.

Proved reserve estimates are adjusted annually in the fourth quarter and during the year if significant changes occur, and take into account recent production and subsurface information about each field. Also, as required by current authoritative guidelines, the estimated future date when an asset will be permanently shut down for economic reasons is based on 12-month average prices and current costs. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Generally, our proved reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to production sharing contracts, reported under the "economic interest" method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. We would expect reserves from these contracts to decrease when product prices rise and increase when prices decline.

The estimation of proved developed reserves also is important to the income statement because the proved developed reserve estimate for a field serves as the denominator in the unit-of-production calculation of the DD&A of the capitalized costs for that asset. At year-end 2016, the net book value of productive properties, plants and equipment (PP&E) subject to a unit-of-production calculation was approximately $60 billion and the DD&A recorded on these assets in 2016 was approximately $8.6 billion. The estimated proved developed reserves for our consolidated operations were 4.0 billion BOE at the end of 2015 and 3.7 billion BOE at the end of 2016. If the estimates of proved reserves used in the unit-of-production calculations had been lower by 10 percent across all calculations, before-tax DD&A in 2016 would have increased by an estimated $955 million.

**Impairments**

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. If there is an indication the carrying amount of an asset may not be recovered, the asset is monitored by management through an established process where changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted before-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for exploration and production assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of future production volumes, commodity prices, operating costs and capital decisions, considering all available information at the date of review. Differing assumptions could affect the timing and the amount of an impairment in any period. See Note 9—Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment when there is evidence of a loss in value and annually following updates to corporate planning assumptions. Such evidence of a loss in value might include our inability to recover the carrying amount, the lack of sustained earnings capacity which would justify the current investment amount, or a current fair value less than the investment's carrying amount. When it is determined such a loss in value is other than temporary, an impairment charge is recognized for the difference between the investment's carrying value and its estimated fair value. When determining whether a decline in value is other than temporary, management considers factors such as the length of time and extent of the decline, the investee's financial condition and near-term prospects, and our ability and intention to retain our investment for a period that will be sufficient to allow for any anticipated recovery in the market value of the investment. Since quoted market prices are usually not available, the fair value is typically based on the present value of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate. Differing assumptions could affect the timing and the amount of an impairment of an investment in any period. See the "APLNG" section of Note 7—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for additional information.

**Asset Retirement Obligations and Environmental Costs**

Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at operational sites. Our largest asset removal obligations involve plugging and abandonment of wells, removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska. The fair values of obligations for dismantling and removing these facilities are recorded as a liability and an increase to PP&E at the time of installation of the asset based on estimated discounted costs. Estimating future asset removal costs is difficult. Most of these removal obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. Asset removal technologies and costs, regulatory and other compliance considerations, expenditure timing, and other inputs into valuation of the obligation, including discount and inflation rates, are also subject to change.

Normally, changes in asset removal obligations are reflected in the income statement as increases or decreases to DD&A over the remaining life of the assets. However, for assets at or nearing the end of their operations, as well as previously sold assets for which we retained the asset removal obligation, an increase in the asset removal obligation can result in an immediate charge to earnings, because any increase in PP&E due to the increased obligation would immediately be subject to impairment, due to the low fair value of these properties.

In addition to asset removal obligations, under the above or similar contracts, permits and regulations, we have certain environmental-related projects. These are primarily related to remediation activities required by Canada and various states within the United States at exploration and production sites. Future environmental remediation costs are difficult to estimate because they are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. See Note 10—Asset Retirement Obligations and Accrued Environmental Costs, in the Notes to Consolidated Financial Statements, for additional information.

**Projected Benefit Obligations**

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations and company contribution requirements. For Employee Retirement Income Security Act-governed pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into the plans. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all vested benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Projected benefit obligations are particularly sensitive to the discount rate assumption. A 1 percent decrease in the discount rate assumption would increase projected benefit obligations by $1,100 million. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate assumption would increase annual benefit expense by $90 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $50 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans. We are also exposed to the possibility that lump sum retirement benefits taken from pension plans during the year could exceed the total of service and interest components of annual pension expense and trigger accelerated recognition of a portion of unrecognized net actuarial losses and gains. These benefit payments are based on decisions by plan participants and are therefore difficult to predict. In the event there is a significant reduction in the expected years of future service of present employees or elimination for a significant number of employees the accrual of defined benefits for some or all of their future services, we could recognize a curtailment gain or loss. See Note 18—Employee Benefit Plans, in the Notes to Consolidated Financial Statements, for additional information.

**Contingencies**

A number of claims and lawsuits are made against the company arising in the ordinary course of business. Management exercises judgment related to accounting and disclosure of these claims which includes losses, damages, and underpayments associated with environmental remediation, tax, contracts, and other legal disputes. As we learn new facts concerning contingencies, we reassess our position both with respect to amounts recognized and disclosed considering changes to the probability of additional losses and potential exposure. However, actual losses can and do vary from estimates for a variety of reasons including legal, arbitration, or other third party decisions; settlement discussions; evaluation of scope of damages; interpretation of regulatory or contractual terms; expected timing of future actions; and proportion of liability shared with other responsible parties. Estimated future costs related to contingencies are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes. For additional information on contingent liabilities, see the "Contingencies" section within "Capital Resources and Liquidity."

**CAUTIONARY STATEMENT FOR THE PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995**

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans, and objectives of management for future operations, are forward-looking statements. Examples of forward-looking statements contained in this report include our expected production growth and outlook on the business environment generally, our expected capital budget and capital expenditures, and discussions concerning future dividends. You can often identify our forward-looking statements by 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.

We based the forward-looking statements on our current expectations, estimates and projections about ourselves and the industries in which we operate in general. We caution you these statements are not guarantees of future performance as they involve assumptions that, while made in good faith, may prove to be incorrect, and involve risks and uncertainties we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including, but not limited to, the following:

- Fluctuations in crude oil, bitumen, natural gas, LNG and natural gas liquids prices, including a prolonged decline in these prices relative to historical or future expected levels.
- The impact of recent, significant declines in prices for crude oil, bitumen, natural gas, LNG and natural gas liquids, which may result in recognition of impairment costs on our long-lived assets, leaseholds and nonconsolidated equity investments.
- Potential failures or delays in achieving expected reserve or production levels from existing and future oil and gas developments, including due to operating hazards, drilling risks and the inherent uncertainties in predicting reserves and reservoir performance.
- Inability to maintain reserves replacement rates consistent with prior periods, whether as a result of the recent, significant declines in commodity prices or otherwise.
- Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.
- Unexpected changes in costs or technical requirements for constructing, modifying or operating exploration and production facilities.
- Legislative and regulatory initiatives addressing environmental concerns, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, bitumen, natural gas, LNG and natural gas liquids.
- Inability to timely obtain or maintain permits, including those necessary for drilling and/or development, construction of LNG terminals or regasification facilities; failure to comply with applicable laws and regulations; or inability to make capital expenditures required to maintain compliance with any necessary permits or applicable laws or regulations.
- Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future exploration and production and LNG development.
- Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events, war, terrorism, cyber attacks or infrastructure constraints or disruptions.
- Changes in international monetary conditions and exchange controls, including changes in foreign currency exchange rates.
- Reduced demand for our products or the use of competing energy products, including alternative energy sources.

- Substantial investment in and development of alternative energy sources, including as a result of existing or future environmental rules and regulations.
- Liability for remedial actions, including removal and reclamation obligations, under environmental regulations.
- Liability resulting from litigation.
- General domestic and international economic and political developments, including armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, bitumen, natural gas, LNG and natural gas liquids pricing, regulation or taxation; and other political, economic or diplomatic developments.
- Volatility in the commodity futures markets.
- Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business.
- Competition in the oil and gas exploration and production industry.
- Any limitations on our access to capital or increase in our cost of capital related to illiquidity or uncertainty in the domestic or international financial markets.
- Our inability to execute asset dispositions or delays in the completion of any asset dispositions we elect to pursue.
- Our inability to obtain economical financing for development, construction or modification of facilities and general corporate purposes.
- The operation and financing of our joint ventures.
- The ability of our customers and other contractual counterparties to satisfy their obligations to us.
- Our inability to realize anticipated cost savings and expenditure reductions.
- The factors generally described in Item 1A—Risk Factors in this report.

## Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

### Financial Instrument Market Risk

We and certain of our subsidiaries hold and issue derivative contracts and financial instruments that expose our cash flows or earnings to changes in commodity prices, foreign currency exchange rates or interest rates. We may use financial and commodity-based derivative contracts to manage the risks produced by changes in the prices of natural gas, crude oil and related products; fluctuations in interest rates and foreign currency exchange rates; or to capture market opportunities.

Our use of derivative instruments is governed by an "Authority Limitations" document approved by our Board of Directors that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity. The Authority Limitations document also establishes the Value at Risk (VaR) limits for the company, and compliance with these limits is monitored daily. The Executive Vice President of Finance, Commercial, and Chief Financial Officer, who reports to the Chief Executive Officer, monitors commodity price risk and risks resulting from foreign currency exchange rates and interest rates. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, and monitors risks.

*Commodity Price Risk*

Our Commercial organization uses futures, forwards, swaps and options in various markets to accomplish the following objectives:

- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas consumers, to floating market prices.
- Enable us to use market knowledge to capture opportunities such as moving physical commodities to more profitable locations and storing commodities to capture seasonal or time premiums. We may use derivatives to optimize these activities.

We use a VaR model to estimate the loss in fair value that could potentially result on a single day from the effect of adverse changes in market conditions on the derivative financial instruments and derivative commodity instruments we hold or issue, including commodity purchases and sales contracts recorded on the balance sheet at December 31, 2016, as derivative instruments. Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes or held for purposes other than trading at December 31, 2016 and 2015, was immaterial to our consolidated cash flows and net income attributable to ConocoPhillips.

*Interest Rate Risk*

The following table provides information about our financial instruments that are sensitive to changes in U.S. interest rates. The debt portion of the table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on effective rates at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. The fair value of the fixed-rate financial instruments is estimated based on quoted market prices.

| | Millions of Dollars Except as Indicated | | | |
|---|---|---|---|---|
| | Debt | | | |
| Expected Maturity Date | Fixed Rate Maturity | Average Interest Rate | Floating Rate Maturity | Average Interest Rate |
| **Year-End 2016** | | | | |
| 2017 | **$ 1,001** | **1.06 %** | **$ -** | **- %** |
| 2018 | **1,570** | **3.63** | **250** | **1.24** |
| 2019 | **2,250** | **5.75** | **1,450** | **2.31** |
| 2020 | **1,500** | **4.73** | **-** | **-** |
| 2021 | **2,150** | **4.08** | **-** | **-** |
| Remaining years | **15,221** | **5.77** | **783** | **1.43** |
| Total | **$ 23,692** | | **$ 2,483** | |
| Fair value | **$ 26,824** | | **$ 2,483** | |
| Year-End 2015 | | | | |
| 2016 | $ 1,250 | 5.63 % | $ 108 | 0.35 % |
| 2017 | 1,024 | 1.03 | - | - |
| 2018 | 1,547 | 3.68 | 250 | 0.69 |
| 2019 | 2,250 | 5.75 | 695 | 0.35 |
| 2020 | 1,500 | 4.73 | - | - |
| Remaining years | 14,371 | 5.72 | 783 | 0.81 |
| Total | $ 21,942 | | $ 1,836 | |
| Fair value | $ 22,949 | | $ 1,836 | |

*Foreign Currency Exchange Risk*
We have foreign currency exchange rate risk resulting from international operations. We do not comprehensively hedge the exposure to currency exchange rate changes although we may choose to selectively hedge certain foreign currency exchange rate exposures, such as firm commitments for capital projects or local currency tax payments, dividends and cash returns from net investments in foreign affiliates to be remitted within the coming year.

At December 31, 2016 and 2015, we held foreign currency exchange forwards hedging cross-border commercial activity and foreign currency exchange swaps for purposes of mitigating our cash-related exposures. Although these forwards and swaps hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting. As a result, the change in the fair value of these foreign currency exchange derivatives is recorded directly in earnings. Since the gain or loss on the swaps is offset by the gain or loss from remeasuring the related cash balances, and since our aggregate position in the forwards was not material, there would be no material impact to our income from an adverse hypothetical 10 percent change in the December 31, 2016, or 2015, exchange rates. The notional and fair market values of these positions at December 31, 2016 and 2015, were as follows:

| **Foreign Currency Exchange Derivatives** | | In Millions | | | |
|---|---|---|---|---|---|
| | | Notional* | | Fair Market Value** | |
| | | **2016** | 2015 | **2016** | 2015 |
| Sell U.S. dollar, buy British pound | USD | **-** | 200 | $ **-** | (3) |
| Sell U.S. dollar, buy Canadian dollar | USD | **13** | - | **-** | - |
| Sell U.S. dollar, buy Norwegian krone | USD | **-** | 147 | **-** | (2) |
| Buy U.S. dollar, sell Canadian dollar | USD | **-** | 20 | **-** | 2 |
| Buy U.S. dollar, sell British pound | USD | **25** | - | **-** | - |
| Buy British pound, sell Canadian dollar | GBP | **1,069** | 564 | **(168)** | 44 |
| Buy British pound, sell Euro | GBP | **-** | 3 | **-** | (1) |
| Sell British pound, buy Norwegian krone | GBP | **51** | - | **1** | - |

**Denominated in U.S. dollars (USD) and British pound (GBP).*
***Denominated in U.S. dollars.*

For additional information about our use of derivative instruments, see Note 14—Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

## Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### CONOCOPHILLIPS

### INDEX TO FINANCIAL STATEMENTS

## Report of Management

Management prepared, and is responsible for, the consolidated financial statements and the other information appearing in this annual report. The consolidated financial statements present fairly the company's financial position, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its consolidated financial statements, the company includes amounts that are based on estimates and judgments management believes are reasonable under the circumstances. The company's financial statements have been audited by Ernst & Young LLP, an independent registered public accounting firm appointed by the Audit and Finance Committee of the Board of Directors and ratified by stockholders. Management has made available to Ernst & Young LLP all of the company's financial records and related data, as well as the minutes of stockholders' and directors' meetings.

**Assessment of Internal Control Over Financial Reporting**

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. ConocoPhillips' internal control system was designed to provide reasonable assurance to the company's management and directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2016. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework (2013)*. Based on our assessment, we believe the company's internal control over financial reporting was effective as of December 31, 2016.

Ernst & Young LLP has issued an audit report on the company's internal control over financial reporting as of December 31, 2016, and their report is included herein.

/s/ Ryan M. Lance

**Ryan M. Lance**
Chairman and
Chief Executive Officer

/s/ Don E. Wallette, Jr.

**Don E. Wallette, Jr.**
Executive Vice President, Finance,
Commercial and
Chief Financial Officer

February 21, 2017

## Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
ConocoPhillips

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the related condensed consolidating financial information listed in the Index at Item 8 and financial statement schedule listed in Item 15(a). These financial statements, condensed consolidating financial information, and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements, condensed consolidating financial information, and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of ConocoPhillips at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related condensed consolidating financial information and financial statement schedule, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), ConocoPhillips' internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 21, 2017, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 21, 2017

**Report of Independent Registered Public Accounting Firm**

The Board of Directors and Stockholders
ConocoPhillips

We have audited ConocoPhillips' internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). ConocoPhillips' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included under the heading "Assessment of Internal Control Over Financial Reporting" in the accompanying "Report of Management." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, ConocoPhillips maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2016 consolidated financial statements of ConocoPhillips and our report dated February 21, 2017, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 21, 2017

## Consolidated Income Statement

**ConocoPhillips**

Years Ended December 31

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2016** | 2015 | 2014 |
| **Revenues and Other Income** | | | | |
| Sales and other operating revenues | $ | **23,693** | 29,564 | 52,524 |
| Equity in earnings of affiliates | | **52** | 655 | 2,529 |
| Gain on dispositions | | **360** | 591 | 98 |
| Other income | | **255** | 125 | 366 |
| Total Revenues and Other Income | | **24,360** | 30,935 | 55,517 |
| **Costs and Expenses** | | | | |
| Purchased commodities | | **9,994** | 12,426 | 22,099 |
| Production and operating expenses | | **5,667** | 7,016 | 8,909 |
| Selling, general and administrative expenses | | **723** | 953 | 735 |
| Exploration expenses | | **1,915** | 4,192 | 2,045 |
| Depreciation, depletion and amortization | | **9,062** | 9,113 | 8,329 |
| Impairments | | **139** | 2,245 | 856 |
| Taxes other than income taxes | | **739** | 901 | 2,088 |
| Accretion on discounted liabilities | | **425** | 483 | 484 |
| Interest and debt expense | | **1,245** | 920 | 648 |
| Foreign currency transaction gains | | **(19)** | (75) | (66) |
| Total Costs and Expenses | | **29,890** | 38,174 | 46,127 |
| Income (loss) from continuing operations before income taxes | | **(5,530)** | (7,239) | 9,390 |
| Income tax provision (benefit) | | **(1,971)** | (2,868) | 3,583 |
| **Income (Loss) From Continuing Operations** | | **(3,559)** | (4,371) | 5,807 |
| Income from discontinued operations* | | **-** | - | 1,131 |
| Net income (loss) | | **(3,559)** | (4,371) | 6,938 |
| Less: net income attributable to noncontrolling interests | | **(56)** | (57) | (69) |
| **Net Income (Loss) Attributable to ConocoPhillips** | $ | **(3,615)** | (4,428) | 6,869 |
| **Amounts Attributable to ConocoPhillips Common Shareholders:** | | | | |
| Income (loss) from continuing operations | $ | **(3,615)** | (4,428) | 5,738 |
| Income from discontinued operations* | | **-** | - | 1,131 |
| Net Income (Loss) | $ | **(3,615)** | (4,428) | 6,869 |
| **Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock** *(dollars)* | | | | |
| Basic | | | | |
| Continuing operations | $ | **(2.91)** | (3.58) | 4.63 |
| Discontinued operations | | **-** | - | 0.91 |
| Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock | $ | **(2.91)** | (3.58) | 5.54 |
| Diluted | | | | |
| Continuing operations | $ | **(2.91)** | (3.58) | 4.60 |
| Discontinued operations | | **-** | - | 0.91 |
| Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock | $ | **(2.91)** | (3.58) | 5.51 |
| **Dividends Paid Per Share of Common Stock** *(dollars)* | $ | **1.00** | 2.94 | 2.84 |
| **Average Common Shares Outstanding** *(in thousands)* | | | | |
| Basic | | **1,245,440** | 1,241,919 | 1,237,325 |
| Diluted | | **1,245,440** | 1,241,919 | 1,245,863 |
| **Net of provision for income taxes on discontinued operations of:* | *$* | **-** | *-* | *16* |

*See Notes to Consolidated Financial Statements.*

## Consolidated Statement of Comprehensive Income **ConocoPhillips**

| Years Ended December 31 | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2016** | 2015 | 2014 |
| **Net Income (Loss)** | **$** | **(3,559)** | (4,371) | 6,938 |
| Other comprehensive income (loss) | | | | |
| Defined benefit plans | | | | |
| Prior service credit (cost) arising during the period | | **23** | 301 | (3) |
| Reclassification adjustment for amortization of prior service credit included in net income | | **(35)** | (19) | (6) |
| Net change | | **(12)** | 282 | (9) |
| Net actuarial gain (loss) arising during the period | | **(481)** | 592 | (840) |
| Reclassification adjustment for amortization of net actuarial losses included in net income | | **309** | 403 | 131 |
| Net change | | **(172)** | 995 | (709) |
| Nonsponsored plans* | | **2** | 1 | - |
| Income taxes on defined benefit plans | | **78** | (460) | 281 |
| Defined benefit plans, net of tax | | **(104)** | 818 | (437) |
| Foreign currency translation adjustments | | **153** | (5,199) | (3,539) |
| Reclassification adjustment for gain included in net income | | **5** | - | - |
| Income taxes on foreign currency translation adjustments | | **-** | 36 | 72 |
| Foreign currency translation adjustments, net of tax | | **158** | (5,163) | (3,467) |
| **Other Comprehensive Income (Loss), Net of Tax** | | **54** | (4,345) | (3,904) |
| **Comprehensive Income (Loss)** | | **(3,505)** | (8,716) | 3,034 |
| Less: comprehensive income attributable to noncontrolling interests | | **(56)** | (57) | (69) |
| **Comprehensive Income (Loss) Attributable to ConocoPhillips** | **$** | **(3,561)** | (8,773) | 2,965 |

**Plans for which ConocoPhillips is not the primary obligor—primarily those administered by equity affiliates.*
*See Notes to Consolidated Financial Statements.*

| **Consolidated Balance Sheet** | | | **ConocoPhillips** |
|---|---|---|---|
| At December 31 | | Millions of Dollars | |
| | | **2016** | 2015 |
| **Assets** | | | |
| Cash and cash equivalents | $ | **3,610** | 2,368 |
| Short-term investments | | **50** | - |
| Accounts and notes receivable (net of allowance of $5 million in 2016 and $7 million in 2015) | | **3,249** | 4,314 |
| Accounts and notes receivable—related parties | | **165** | 200 |
| Inventories | | **1,018** | 1,124 |
| Prepaid expenses and other current assets | | **517** | 783 |
| Total Current Assets | | **8,609** | 8,789 |
| Investments and long-term receivables | | **21,091** | 20,490 |
| Loans and advances—related parties | | **581** | 696 |
| Net properties, plants and equipment (net of accumulated depreciation, depletion and amortization of $73,075 million in 2016 and $70,413 million in 2015) | | **58,331** | 66,446 |
| Other assets | | **1,160** | 1,063 |
| Total Assets | $ | **89,772** | 97,484 |
| **Liabilities** | | | |
| Accounts payable | $ | **3,631** | 4,895 |
| Accounts payable—related parties | | **22** | 38 |
| Short-term debt | | **1,089** | 1,427 |
| Accrued income and other taxes | | **484** | 499 |
| Employee benefit obligations | | **689** | 887 |
| Other accruals | | **994** | 1,510 |
| Total Current Liabilities | | **6,909** | 9,256 |
| Long-term debt | | **26,186** | 23,453 |
| Asset retirement obligations and accrued environmental costs | | **8,425** | 9,580 |
| Deferred income taxes | | **8,949** | 10,999 |
| Employee benefit obligations | | **2,552** | 2,286 |
| Other liabilities and deferred credits | | **1,525** | 1,828 |
| Total Liabilities | | **54,546** | 57,402 |
| **Equity** | | | |
| Common stock (2,500,000,000 shares authorized at $.01 par value) | | | |
| Issued (2016—1,782,079,107 shares; 2015—1,778,226,388 shares) | | | |
| Par value | | **18** | 18 |
| Capital in excess of par | | **46,507** | 46,357 |
| Treasury stock (at cost: 2016—544,809,771 shares; 2015—542,230,673 shares) | | **(36,906)** | (36,780) |
| Accumulated other comprehensive loss | | **(6,193)** | (6,247) |
| Retained earnings | | **31,548** | 36,414 |
| Total Common Stockholders' Equity | | **34,974** | 39,762 |
| Noncontrolling interests | | **252** | 320 |
| Total Equity | | **35,226** | 40,082 |
| Total Liabilities and Equity | $ | **89,772** | 97,484 |

*See Notes to Consolidated Financial Statements.*

## Consolidated Statement of Cash Flows — ConocoPhillips

| Years Ended December 31 | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2016** | 2015 | 2014 |
| **Cash Flows From Operating Activities** | | | | |
| Net income (loss) | $ | **(3,559)** | (4,371) | 6,938 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities | | | | |
| Depreciation, depletion and amortization | | **9,062** | 9,113 | 8,329 |
| Impairments | | **139** | 2,245 | 856 |
| Dry hole costs and leasehold impairments | | **1,184** | 3,065 | 1,166 |
| Accretion on discounted liabilities | | **425** | 483 | 484 |
| Deferred taxes | | **(2,221)** | (2,772) | 709 |
| Undistributed equity earnings | | **299** | 101 | 77 |
| Gain on dispositions | | **(360)** | (591) | (98) |
| Income from discontinued operations | | **-** | - | (1,131) |
| Other | | **(85)** | 321 | (233) |
| Working capital adjustments | | | | |
| Decrease in accounts and notes receivable | | **820** | 1,810 | 1,227 |
| Decrease (increase) in inventories | | **44** | 166 | (193) |
| Decrease (increase) in prepaid expenses and other current assets | | **105** | 239 | (190) |
| Decrease in accounts payable | | **(524)** | (1,647) | (963) |
| Decrease in taxes and other accruals | | **(926)** | (590) | (566) |
| Net cash provided by continuing operating activities | | **4,403** | 7,572 | 16,412 |
| Net cash provided by discontinued operations | | **-** | - | 157 |
| Net Cash Provided by Operating Activities | | **4,403** | 7,572 | 16,569 |
| **Cash Flows From Investing Activities** | | | | |
| Capital expenditures and investments | | **(4,869)** | (10,050) | (17,085) |
| Working capital changes associated with investing activities | | **(331)** | (968) | 180 |
| Proceeds from asset dispositions | | **1,286** | 1,952 | 1,603 |
| Net sales (purchases) of short-term investments | | **(51)** | - | 253 |
| Collection of advances/loans—related parties | | **108** | 105 | 603 |
| Other | | **(2)** | 306 | (446) |
| Net cash used in continuing investing activities | | **(3,859)** | (8,655) | (14,892) |
| Net cash used in discontinued operations | | **-** | - | (73) |
| Net Cash Used in Investing Activities | | **(3,859)** | (8,655) | (14,965) |
| **Cash Flows From Financing Activities** | | | | |
| Issuance of debt | | **4,594** | 2,498 | 2,994 |
| Repayment of debt | | **(2,251)** | (103) | (2,014) |
| Issuance of company common stock | | **(63)** | (82) | 35 |
| Repurchase of company common stock | | **(126)** | - | - |
| Dividends paid | | **(1,253)** | (3,664) | (3,525) |
| Other | | **(137)** | (78) | (64) |
| Net Cash Provided by (Used in) Financing Activities | | **764** | (1,429) | (2,574) |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | | **(66)** | (182) | (214) |
| **Net Change in Cash and Cash Equivalents** | | **1,242** | (2,694) | (1,184) |
| Cash and cash equivalents at beginning of period | | **2,368** | 5,062 | 6,246 |
| Cash and Cash Equivalents at End of Period | $ | **3,610** | 2,368 | 5,062 |

*See Notes to Consolidated Financial Statements.*

| | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Attributable to ConocoPhillips | | | | | | | |
| | Common Stock | | | | | | | |
| | | Par Value | Capital in Excess of Par | Treasury Stock | Accum. Other Comprehensive Income (Loss) | Retained Earnings | Non-Controlling Interests | Total |
| December 31, 2013 | $ | 18 | 45,690 | (36,780) | 2,002 | 41,160 | 402 | 52,492 |
| Net income | | | | | | 6,869 | 69 | 6,938 |
| Other comprehensive loss | | | | | (3,904) | | | (3,904) |
| Dividends paid | | | | | | (3,525) | | (3,525) |
| Distributions to noncontrolling interests and other | | | | | | | (109) | (109) |
| Distributed under benefit plans | | | 381 | | | | | 381 |
| December 31, 2014 | $ | 18 | 46,071 | (36,780) | (1,902) | 44,504 | 362 | 52,273 |
| Net income (loss) | | | | | | (4,428) | 57 | (4,371) |
| Other comprehensive loss | | | | | (4,345) | | | (4,345) |
| Dividends paid | | | | | | (3,664) | | (3,664) |
| Distributions to noncontrolling interests and other | | | | | | | (100) | (100) |
| Distributed under benefit plans | | | 286 | | | | | 286 |
| Other | | | | | | 2 | 1 | 3 |
| December 31, 2015 | $ | 18 | 46,357 | (36,780) | (6,247) | 36,414 | 320 | 40,082 |
| Net income (loss) | | | | | | **(3,615)** | **56** | **(3,559)** |
| Other comprehensive income | | | | | **54** | | | **54** |
| Dividends paid | | | | | | **(1,253)** | | **(1,253)** |
| Repurchase of company common stock | | | | **(126)** | | | | **(126)** |
| Distributions to noncontrolling interests and other | | | | | | | **(124)** | **(124)** |
| Distributed under benefit plans | | | **150** | | | | | **150** |
| Other | | | | | | **2** | | **2** |
| **December 31, 2016** | **$** | **18** | **46,507** | **(36,906)** | **(6,193)** | **31,548** | **252** | **35,226** |

*See Notes to Consolidated Financial Statements.*

**Note 1—Accounting Policies**

- **Consolidation Principles and Investments**—Our consolidated financial statements include the accounts of majority-owned, controlled subsidiaries and variable interest entities where we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we have the ability to exert significant influence over the affiliates' operating and financial policies. When we do not have the ability to exert significant influence, the investment is either classified as available-for-sale if fair value is readily determinable, or the cost method is used if fair value is not readily determinable. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants and terminals are consolidated on a proportionate basis. Other securities and investments are generally carried at cost.

  We manage our operations through six operating segments, defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International. For additional information, see Note 24—Segment Disclosures and Related Information. Unless indicated otherwise, the information in the Notes to the Consolidated Financial Statements relates to our continuing operations.

- **Foreign Currency Translation**—Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in accumulated other comprehensive income in common stockholders' equity. Foreign currency transaction gains and losses are included in current earnings. Most of our foreign operations use their local currency as the functional currency.

- **Use of Estimates**—The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from these estimates.

- **Revenue Recognition**—Revenues associated with sales of crude oil, bitumen, natural gas, liquefied natural gas (LNG), natural gas liquids and other items are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, either immediately or within a fixed delivery schedule that is reasonable and customary in the industry.

  Revenues associated with producing properties in which we have an interest with other producers are recognized based on the actual volumes we sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, which are deemed to be nonrecoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are generally not significant.

  Revenues associated with transactions commonly called buy/sell contracts, in which the purchase and sale of inventory with the same counterparty are entered into "in contemplation" of one another, are combined and reported net (i.e., on the same income statement line).

- **Shipping and Handling Costs**—We include shipping and handling costs in production and operating expenses for production activities. Transportation costs related to marketing activities are recorded in purchased commodities. Freight costs billed to customers are recorded as a component of revenue.

- **Cash Equivalents**—Cash equivalents are highly liquid, short-term investments that are readily convertible to known amounts of cash and have original maturities of 90 days or less from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.

- **Short-Term Investments**—Investments in bank time deposits and marketable securities (commercial paper and government obligations) with original maturities of greater than 90 days but less than one year are classified as short-term investments.

- **Inventories**—We have several valuation methods for our various types of inventories and consistently use the following methods for each type of inventory. Commodity-related inventories are valued at the lower of cost or market in the aggregate, primarily on the last-in, first-out (LIFO) basis. Any necessary lower-of-cost-or-market write-downs at year end are recorded as permanent adjustments to the LIFO cost basis. LIFO is used to better match current inventory costs with current revenues. Costs include both direct and indirect expenditures incurred in bringing an item or product to its existing condition and location, but not unusual/nonrecurring costs or research and development costs. Materials, supplies and other miscellaneous inventories, such as tubular goods and well equipment, are valued using various methods, including the weighted-average-cost method, and the first-in, first-out (FIFO) method, consistent with industry practice.

- **Fair Value Measurements**—Assets and liabilities measured at fair value and required to be categorized within the fair value hierarchy are categorized into one of three different levels depending on the observability of the inputs employed in the measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1 for the asset or liability, either directly or indirectly through market-corroborated inputs. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or our assumptions about pricing by market participants.

- **Derivative Instruments**—Derivative instruments are recorded on the balance sheet at fair value. If the right of offset exists and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the balance sheet and the collateral payable or receivable is netted against derivative assets and derivative liabilities, respectively.

  Recognition and classification of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives not accounted for as hedges are recognized immediately in earnings. For derivative instruments that are designated and qualify as a fair value hedge, the gains or losses from adjusting the derivative to its fair value will be immediately recognized in earnings and, to the extent the hedge is effective, offset the concurrent recognition of changes in the fair value of the hedged item.

- **Oil and Gas Exploration and Development**—Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

  **Property Acquisition Costs**—Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption properties, plants and equipment (PP&E). Leasehold impairment is recognized based on exploratory experience and management's judgment. Upon achievement of all conditions necessary for reserves to be classified as proved, the associated leasehold costs are reclassified to proved properties.

  **Exploratory Costs**—Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized, or "suspended," on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas resources are designated as proved reserves.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as dry holes when it judges the potential field does not warrant further investment in the near term. See Note 8—Suspended Wells and Other Exploration Expenses, for additional information on suspended wells.

**Development Costs**—Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

**Depletion and Amortization**—Leasehold costs of producing properties are depleted using the unit-of-production method based on estimated proved oil and gas reserves. Amortization of intangible development costs is based on the unit-of-production method using estimated proved developed oil and gas reserves.

- **Capitalized Interest**—Interest from external borrowings is capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets.

- **Depreciation and Amortization**—Depreciation and amortization of PP&E on producing hydrocarbon properties and certain pipeline assets (those which are expected to have a declining utilization pattern), are determined by the unit-of-production method. Depreciation and amortization of all other PP&E are determined by either the individual-unit-straight-line method or the group-straight-line method (for those individual units that are highly integrated with other units).

- **Impairment of Properties, Plants and Equipment**—PP&E used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. If there is an indication the carrying amount of an asset may not be recovered, the asset is monitored by management through an established process where changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted before-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value through additional amortization or depreciation provisions and reported as impairments in the periods in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for exploration and production assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell, with fair value determined using a binding negotiated price, if available, or present value of expected future cash flows as previously described.

  The expected future cash flows used for impairment reviews and related fair value calculations are based on estimated future production volumes, prices and costs, considering all available evidence at the date of review. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. Additionally, when probable and possible reserves exist, an appropriate risk-adjusted amount of these reserves may be included in the impairment calculation.

- **Impairment of Investments in Nonconsolidated Entities**—Investments in nonconsolidated entities are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred and annually following updates to corporate planning assumptions. When such a condition is judgmentally determined to be other than temporary, the carrying value of the investment is written down to fair value. The fair value of the impaired investment is based on quoted market prices, if available, or upon the present value of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate.

- **Maintenance and Repairs**—Costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

- **Property Dispositions**—When complete units of depreciable property are sold, the asset cost and related accumulated depreciation are eliminated, with any gain or loss reflected in the "Gain on dispositions" line of our consolidated income statement. When less than complete units of depreciable property are disposed of or retired, the difference between asset cost and salvage value is charged or credited to accumulated depreciation.

- **Asset Retirement Obligations and Environmental Costs**—The fair value of legal obligations to retire and remove long-lived assets are recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time the liability is increased for the change in its present value, and the capitalized cost in PP&E is depreciated over the useful life of the related asset. For additional information, see Note 10—Asset Retirement Obligations and Accrued Environmental Costs.

  Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures relating to an existing condition caused by past operations, and those having no future economic benefit, are expensed. Liabilities for environmental expenditures are recorded on an undiscounted basis (unless acquired in a purchase business combination, which we record on a discounted basis) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is probable and estimable.

- **Guarantees**—The fair value of a guarantee is determined and recorded as a liability at the time the guarantee is given. The initial liability is subsequently reduced as we are released from exposure under the guarantee. We amortize the guarantee liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of guarantee. In cases where the guarantee term is indefinite, we reverse the liability when we have information indicating the liability is essentially relieved or amortize it over an appropriate time period as the fair value of our guarantee exposure declines over time. We amortize the guarantee liability to the related income statement line item based on the nature of the guarantee. When it becomes probable that we will have to perform on a guarantee, we accrue a separate liability if it is reasonably estimable, based on the facts and circumstances at that time. We reverse the fair value liability only when there is no further exposure under the guarantee.

- **Share-Based Compensation**—We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award) or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. We have elected to recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

- **Income Taxes**—Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial reporting basis and the tax basis of our assets and liabilities, except for deferred taxes on income and temporary differences related to the cumulative translation adjustment considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures. Allowable tax credits are applied currently as reductions of the provision for income taxes. Interest related to unrecognized tax benefits is reflected in interest and debt expense, and penalties related to unrecognized tax benefits are reflected in production and operating expenses.

- **Taxes Collected from Customers and Remitted to Governmental Authorities**—Sales and value-added taxes are recorded net.

- **Net Income (Loss) Per Share of Common Stock**—Basic net income (loss) per share of common stock is calculated based upon the daily weighted-average number of common shares outstanding during the year. Also, this calculation includes fully vested stock and unit awards that have not yet been issued as common stock, along with an adjustment to net income (loss) for dividend equivalents paid on unvested unit awards that are considered participating securities. Diluted net income per share of common stock includes unvested stock, unit or option awards granted under our compensation plans and vested but unexercised stock options, but only to the extent these instruments dilute net income per share, primarily under the treasury-stock method. Diluted net loss per share, which is calculated the same as basic net loss per share, does not assume conversion or exercise of securities that would have an antidilutive effect. Treasury stock is excluded from the daily weighted-average number of common shares outstanding in both calculations. The earnings per share impact of the participating securities is immaterial.

## Note 2—Change in Accounting Principles

We adopted the provisions of Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) No. 2015-02, "Amendments to the Consolidation Analysis," beginning January 1, 2016. The ASU amends existing requirements applicable to reporting entities that are required to evaluate whether certain legal entities, including variable interest entities (VIEs), should be consolidated. The adoption of this ASU did not have an impact on our consolidated financial statements and disclosures. See Note 4 —Variable Interest Entities, for additional information on our significant VIEs.

## Note 3—Discontinued Operations

On December 20, 2012, we entered into agreements with affiliates of Oando PLC to sell our Nigeria business, which was previously part of the Other International operating segment. On July 30, 2014, we completed the sale for $1,359 million, inclusive of $550 million deposits previously received. The deposits had been included in the "Other accruals" line on our consolidated balance sheet and in the "Other" line of cash flows from investing activities on our consolidated statement of cash flows. The deposits received included $435 million in 2012, $15 million in 2013, and $100 million in 2014. We recognized a before-tax gain of $1,052 million, which is included in the "Income from discontinued operations" line on our consolidated income statement.

Sales and other operating revenues and income from discontinued operations related to the Nigeria business during 2014 were as follows:

| | Millions of Dollars |
|---|---|
| | 2014 |
| Sales and other operating revenues from discontinued operations | $ 480 |
| Income from discontinued operations before-tax | $ 1,147 |
| Income tax expense | 16 |
| Income from discontinued operations | $ 1,131 |

## Note 4—Variable Interest Entities (VIEs)

We hold variable interests in VIEs that have not been consolidated because we are not considered the primary beneficiary. Information on our significant VIEs follows:

**Australia Pacific LNG Pty Ltd (APLNG)**
APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary of APLNG because we share with Origin Energy and China Petrochemical Corporation (Sinopec) the power to direct the key activities of APLNG that most significantly impact its economic performance, which involve activities related to the production and commercialization of coalbed methane, as well as LNG processing and export marketing. As a result, we do not consolidate APLNG, and it is accounted for as an equity method investment.

As of December 31, 2016, we have not provided any financial support to APLNG other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of APLNG. See Note 7—Investments, Loans and Long-Term Receivables, and Note 12—Guarantees, for additional information.

**Marine Well Containment Company, LLC (MWCC)**
MWCC provides well containment equipment and technology and related services in the deepwater U.S. Gulf of Mexico. Its principal activities involve the development and maintenance of rapid-response hydrocarbon well containment systems that are deployable in the Gulf of Mexico on a call-out basis. We have a 10 percent ownership interest in MWCC, and it is accounted for as an equity method investment because MWCC is a limited liability company in which we are a Founding Member and exercise significant influence through our permanent seat on the ten member Executive Committee responsible for overseeing the affairs of MWCC. During the year ended December 31, 2016, MWCC executed a $154 million term loan financing arrangement with an external financial institution whose terms required the financing be secured by letters of credit provided by certain owners of MWCC, including ConocoPhillips. In connection with the financing transaction, we issued a letter of credit of $22 million which can be drawn upon in the event of a default by MWCC on its obligation to repay the proceeds of the term loan. The fair value of this letter of credit is immaterial and not recognized on our consolidated balance sheet. MWCC is considered a VIE, as it has entered into arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary and do not consolidate MWCC because we share the power to govern the business and operation of the company and to undertake certain obligations that most significantly impact its economic performance with nine other unaffiliated owners of MWCC.

At December 31, 2016, the book value of our equity method investment in MWCC was $148 million. We have not provided any financial support to MWCC other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of MWCC.

## Note 5—Inventories

Inventories at December 31 were:

| | Millions of Dollars | |
|---|---|---|
| | **2016** | 2015 |
| Crude oil and natural gas | $ **418** | 406 |
| Materials and supplies | **600** | 718 |
| | $ **1,018** | 1,124 |

Inventories valued on the LIFO basis totaled $269 million and $317 million at December 31, 2016 and 2015, respectively. The estimated excess of current replacement cost over LIFO cost of inventories was approximately $104 million and $6 million at December 31, 2016 and December 31, 2015, respectively. In 2016, liquidation of LIFO inventory values increased the net loss from continuing operations by $9 million.

**Note 6—Assets Held for Sale or Sold**

**Assets Sold**
All gains or losses are reported before-tax and are included net in the "Gain on dispositions" line on our consolidated income statement.

*2016*
On April 22, 2016, we sold our interest in the Alaska Beluga River Unit natural gas field in the Cook Inlet for $134 million, net of settlement of gas imbalances and customary adjustments, and recognized a gain on disposition of $56 million. At the time of disposition, the net carrying value of our Beluga River Unit interest, which was included in the Alaska segment, was $78 million, consisting primarily of $100 million of PP&E and $19 million of asset retirement obligations (ARO).

On October 13, 2016, we completed an asset exchange with Bonavista Energy in which we gave up approximately 141,000 net acres of non-core developed properties in central Alberta in exchange for approximately 40,000 net acres of primarily undeveloped properties in northeast British Columbia. The fair value of the transaction was determined to be approximately $69 million and a before-tax impairment of $57 million was recognized in the third quarter of 2016 when the assets were considered held for sale, to reduce the carrying value to fair value. In the fourth quarter, a loss on disposition of approximately $1 million was recognized upon completion of the transaction. The divested properties were included in the Canada segment.

On October 28, 2016, we sold ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal for $442 million and recognized a gain on disposition of $146 million. At the time of disposition, the carrying value of our interest was $286 million, which was primarily PP&E. Senegal results of operations were reported within our Other International segment.

On November 17, 2016, we completed the sale of our 40 percent interest in South Natuna Sea Block B for $225 million and recognized a loss on disposition of $26 million. Our interest in Block B was included in the Asia Pacific and Middle East segment. Previously, in the third quarter of 2016, we recognized a before-tax impairment of $42 million at the time it was considered held for sale to reduce the carrying value to fair value. At the time of the disposition, the carrying value of our interest was approximately $251 million, which included primarily $154 million of PP&E, $178 million of accounts receivable, $25 million of inventory, $54 million of deferred tax assets, $130 million of accounts payable and other accruals, and $38 million of employee benefit obligations.

On December 8, 2016, we completed the sale of certain mineral and non-mineral fee lands in northeastern Minnesota, which was included in the Lower 48 segment, for $148 million and recorded a gain on disposition of $4 million. The majority of the assets sold were acquired during the fourth quarter of 2016 as a result of ConocoPhillips holding a reversionary interest in the Greater Northern Iron Ore Properties Trust (the Trust), a grantor trust that owned mineral and surface interests in the Mesabi Iron Range in northeastern Minnesota and certain other personal property. Pursuant to the terms of the Trust Agreement, the Trust terminated on April 6, 2015 and in November 2016, upon completion of the wind-down period, documents memorializing ConocoPhillips' ownership of certain Trust property, including all of the Trust's mineral properties and active leases, were delivered to us and we recognized the fair value of the net assets resulting in a gain of $88 million recorded in the "Other income" line on our consolidated income statement. At the time of the disposition, the carrying value of our interests, which included the assets obtained from the Trust, consisted of $144 million of PP&E.

*2015*
In November 2015, we sold a portion of our western Canadian properties located in British Columbia, Alberta, and Saskatchewan for $198 million and recognized a gain on disposition of $66 million. At the time of the disposition, the carrying value of our interest, which was included in the Canada segment, was $132 million, which included primarily $379 million of PP&E and $248 million of ARO.

In December 2015, we sold a portion of our western Canadian properties located in central Alberta for $130 million and recognized a loss on disposition of $235 million. At the time of the disposition, the carrying value of our interest, which was included in the Canada segment, was approximately $365 million, which included primarily $488 million of PP&E and $126 million of ARO.

Additionally, other December 2015 disposition transactions are summarized below.

We sold producing properties in East Texas and North Louisiana for $412 million and recognized a gain on disposition of $189 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $223 million, which included $351 million of PP&E and $128 million of ARO.

We sold certain gas producing properties in South Texas for $358 million and recognized a gain on disposition of $201 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $157 million, which included $369 million of PP&E and $212 million of ARO.

We sold certain pipeline and gathering assets in South Texas for $201 million and recognized a gain on disposition of $193 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $8 million, which primarily included $24 million of PP&E and $18 million of ARO.

We also sold our 50 percent interest in the Russian joint venture, Polar Lights Company, for $98 million and recognized a gain on disposition of $58 million. At the time of the disposition, the carrying value of our equity method investment in Polar Lights Company, which was included in our Other International segment, was approximately $40 million.

*2014*
For information on the sale of our Nigeria business, which is included in the “Income from discontinued operations” line on our consolidated income statement, see Note 3—Discontinued Operations.

**Note 7—Investments, Loans and Long-Term Receivables**

Components of investments, loans and long-term receivables at December 31 were:

| | Millions of Dollars | |
|---|---|---|
| | **2016** | 2015 |
| Equity investments | $ **20,364** | 19,850 |
| Loans and advances—related parties | **581** | 696 |
| Long-term receivables | **631** | 519 |
| Other investments | **96** | 121 |
| | $ **21,672** | 21,186 |

**Equity Investments**
Affiliated companies in which we had a significant equity investment at December 31, 2016, included:

- APLNG—37.5 percent owned joint venture with Origin Energy (37.5 percent) and Sinopec (25 percent)—to develop coalbed methane production from the Bowen and Surat basins in Queensland, Australia, as well as process and export LNG.
- FCCL Partnership—50 percent owned business venture with Cenovus Energy Inc.—produces bitumen in the Athabasca oil sands in northeastern Alberta and sells the bitumen blend.
- Qatar Liquefied Gas Company Limited (3) (QG3)—30 percent owned joint venture with affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent)—produces and liquefies natural gas from Qatar's North Field, as well as exports LNG.

Summarized 100 percent earnings information for equity method investments in affiliated companies, combined, was as follows:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| Revenues | $ **10,149** | 11,003 | 19,243 |
| Income before income taxes | **660** | 1,866 | 6,746 |
| Net income | **799** | 1,801 | 6,630 |

Summarized 100 percent balance sheet information for equity method investments in affiliated companies, combined, was as follows:

| | Millions of Dollars | |
|---|---|---|
| | **2016** | 2015 |
| Current assets | $ **3,578** | 2,504 |
| Noncurrent assets | **60,243** | 58,431 |
| Current liabilities | **2,352** | 1,863 |
| Noncurrent liabilities | **23,764** | 24,820 |

Our share of income taxes incurred directly by an equity company is reported in equity in earnings of affiliates, and as such is not included in income taxes in our consolidated financial statements.

At December 31, 2016, retained earnings included $1,392 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $398 million, $876 million and $2,648 million in 2016, 2015 and 2014, respectively.

**APLNG**
APLNG is focused on coalbed methane production from the Bowen and Surat basins in Queensland, Australia, and LNG processing and export sales. Our investment in APLNG gives us access to coalbed methane resources in Australia and enhances our LNG position. The majority of APLNG LNG is sold under two long-term sales and purchase agreements, supplemented with sales of additional LNG spot cargoes targeting the Asia Pacific markets. Origin Energy, an integrated Australian energy company, is the operator of APLNG's production and pipeline system, while we operate the LNG facility.

APLNG executed project financing agreements for an $8.5 billion project finance facility in 2012. The $8.5 billion project finance facility is composed of financing agreements executed by APLNG with the Export-Import Bank of the United States for approximately $2.9 billion, the Export-Import Bank of China for approximately $2.7 billion, and a syndicate of Australian and international commercial banks for approximately $2.9 billion. At December 31, 2016, $8.5 billion had been drawn from the facility. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility until the project achieves financial completion. In October 2016, we reached financial completion for Train 1, which reduced our associated guarantee by 60 percent. See Note 12—Guarantees, for additional information.

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. See Note 4—Variable Interest Entities (VIEs) for additional information.

On July 1, 2016, APLNG changed its tax functional currency from Australian dollar to U.S. dollar and translated all APLNG assets and liabilities into U.S. dollar, utilizing the exchange rate as of that date. As a result of this change, we recorded a reduction to our investment in APLNG for the deferred tax effect of $174 million in the "Equity in earnings (losses) of affiliates" line of our consolidated income statement.

During the fourth quarter of 2015, due to the outlook for crude oil and natural gas prices at that time, the estimated fair value of our investment in APLNG declined to an amount below book value. Accordingly, we recorded a noncash $1,502 million before- and after-tax impairment, in our fourth-quarter 2015 results.

During the third quarter of 2016, the outlook for crude oil prices weakened again, and as a result, the estimated fair value of our investment in APLNG declined to an amount below book value as of September 30, 2016. Based on a review of the facts and circumstances surrounding this decline in fair value, we concluded the impairment was not other than temporary under the guidance of FASB Accounting Standards Codification (ASC) Topic 323, "Investments – Equity Method and Joint Ventures."

During the fourth quarter of 2016, primarily due to the impact of accretion on discounted cash flows from the passage of time and strengthening of the U.S. dollar, the estimated fair value of our investment increased and is above book value as of December 31, 2016. The expected future cash flows used for the impairment review of our investment in APLNG are based on estimated future production, an outlook of future prices from a combination of exchanges (short-term) and pricing service companies (long-term), costs, a market outlook of foreign exchange rates provided by a third party, and a discount rate believed to be consistent with those used by principal market participants. Unfavorable changes in any of these assumptions could result in a reduction in future cash flows and could indicate impairment in the future. Subsequent to December 31, 2016, the outlook for crude prices and the U.S. dollar exchange rate relative to the Australian dollar has weakened. If these outlooks remain unchanged, we expect the estimated fair value of our investment in APLNG to be below book value at March 31, 2017.

At December 31, 2016, the book value of our equity method investment in APLNG was $10,089 million. The historical cost basis of our 37.5 percent share of net assets on the books of APLNG under U.S. generally accepted accounting principles was $8,348 million, resulting in a basis difference of $1,741 million on our books. The basis difference, which is substantially all associated with PP&E and subject to amortization, has been allocated on a relative fair value basis to individual exploration and production license areas owned by APLNG, some of which are not currently in production. Any future additional payments are expected to be allocated in a similar manner. Each exploration license area will periodically be reviewed for any indicators of potential impairment, which, if required, would result in acceleration of basis difference amortization. As the joint venture produces natural gas from each license, we amortize the basis difference allocated to that license using the unit-of-production method. Included in net income (loss) attributable to ConocoPhillips for 2016, 2015 and 2014 was after-tax expense of $92 million, $21 million and $24 million, respectively, representing the amortization of this basis difference on currently producing licenses.

**FCCL**

FCCL Partnership, a Canadian upstream 50/50 general partnership with Cenovus Energy Inc., produces bitumen in the Athabasca oil sands in northeastern Alberta and sells the bitumen blend. We account for our investment in FCCL under the equity method of accounting, with the operating results of our investment in FCCL converted to reflect the use of the successful efforts method of accounting for oil and gas exploration and development activities.

At December 31, 2016, the book value of our investment in FCCL was $8,784 million, net of a $1,706 million reduction due to cumulative foreign currency translation effects. FCCL's operating assets consist of the Foster Creek and Christina Lake steam-assisted gravity drainage bitumen projects, both located in the eastern flank of the Athabasca oil sands in northeastern Alberta. Cenovus is the operator and managing partner of FCCL.

We were obligated to contribute $7.5 billion, plus accrued interest, to FCCL over a 10-year period that began in 2007. In December 2013, we repaid the remaining balance of the obligation, which totaled $2,810 million. In the first quarter of 2014, we received a $1.3 billion distribution from FCCL, which is included in the "Undistributed equity earnings" line on our consolidated statement of cash flows.

**QG3**
QG3 is a joint venture that owns an integrated large-scale LNG project located in Qatar. We provided project financing, with a current outstanding balance of $696 million as described below under "Loans and Long-Term Receivables." At December 31, 2016, the book value of our equity method investment in QG3, excluding the project financing, was $869 million. We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliated Golden Pass Pipeline near Sabine Pass, Texas, in which we have a 12.4 percent interest, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from QG3. However, currently the LNG from QG3 is being sold to markets outside of the United States.

**Loans and Long-Term Receivables**
As part of our normal ongoing business operations and consistent with industry practice, we enter into numerous agreements with other parties to pursue business opportunities. Included in such activity are loans and long-term receivables to certain affiliated and non-affiliated companies. Loans are recorded when cash is transferred or seller financing is provided to the affiliated or non-affiliated company pursuant to a loan agreement. The loan balance will increase as interest is earned on the outstanding loan balance and will decrease as interest and principal payments are received. Interest is earned at the loan agreement's stated interest rate. Loans and long-term receivables are assessed for impairment when events indicate the loan balance may not be fully recovered.

Through November 2014, we had an agreement with Freeport LNG Development, L.P. (Freeport LNG) to participate in an LNG receiving terminal in Quintana, Texas. We had no ownership in Freeport LNG; however, we had a 50 percent interest in Freeport LNG GP, Inc. (Freeport GP), which serves as the general partner managing the venture. We had entered into a credit agreement with Freeport LNG, whereby we agreed to provide loan financing for the construction of the terminal. We also entered into a long-term agreement with Freeport LNG to use 0.9 billion cubic feet per day of regasification capacity, which would have expired in 2033. When the terminal became operational in June 2008, we began making payments under the terminal use agreement. Freeport LNG began making loan repayments in September 2008.

In July 2013, we reached an agreement with Freeport LNG to terminate our long-term agreement at the Freeport LNG Terminal, subject to Freeport LNG obtaining regulatory approval and project financing for an LNG liquefaction and export facility in Texas, in which we are not a participant. These conditions were satisfied in 2014, and we paid Freeport LNG a termination fee of $522 million. Freeport LNG repaid the outstanding $454 million ConocoPhillips loan used by Freeport LNG to partially fund the original construction of the terminal. The payment made to Freeport LNG to terminate our long-term agreement is included in the cash flows from operating activities section on our consolidated statement of cash flows, while the receipt of the funds from Freeport LNG to repay the outstanding loan is included in the cash flows from investing activities section in 2014. These transactions, plus miscellaneous items, including the disposal of our 50 percent interest in Freeport GP, resulted in a one-time net cash outflow of $63 million for us. In addition, we recognized an after-tax charge to earnings of $540 million in 2014, and our terminal regasification capacity was reduced to zero.

At December 31, 2016, significant loans to affiliated companies include $696 million in project financing to QG3. We own a 30 percent interest in QG3, for which we use the equity method of accounting. The other participants in the project are affiliates of Qatar Petroleum and Mitsui. QG3 secured project financing of $4.0 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. On December 15, 2011, QG3 achieved financial completion and all project loan facilities became nonrecourse to the project participants. Semi-annual repayments began in January 2011 and will extend through July 2022.

The long-term portion of these loans is included in the "Loans and advances—related parties" line on our consolidated balance sheet, while the short-term portion is in "Accounts and notes receivable—related parties."

**Note 8—Suspended Wells and Other Exploration Expenses**

The following table reflects the net changes in suspended exploratory well costs during 2016, 2015 and 2014:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| Beginning balance at January 1 | $ **1,260** | 1,299 | 994 |
| Additions pending the determination of proved reserves | **225** | 331 | 478 |
| Reclassifications to proved properties | **(27)** | (28) | (9) |
| Sales of suspended well investment | **(247)** | - | (57) |
| Charged to dry hole expense | **(148)** | (342) | (107) |
| Ending balance at December 31 | $ **1,063** | 1,260 | 1,299 |

The following table provides an aging of suspended well balances at December 31:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| Exploratory well costs capitalized for a period of one year or less | $ **132** | 235 | 466 |
| Exploratory well costs capitalized for a period greater than one year | **931** | 1,025 | 833 |
| Ending balance | $ **1,063** | 1,260 | 1,299 |
| Number of projects with exploratory well costs capitalized for a period greater than one year | **26** | 28 | 30 |

The following table provides a further aging of those exploratory well costs that have been capitalized for more than one year since the completion of drilling as of December 31, 2016:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | Suspended Since | | |
| | Total | 2013–2015 | 2010–2012 | 2002–2009 |
| Greater Poseidon—Australia(2) | 177 | 157 | 15 | 5 |
| Shenandoah—Lower 48(1) | 161 | 118 | - | 43 |
| Greater Clair—UK(2) | 131 | 120 | 11 | - |
| Surmont 3 and beyond—Canada(1) | 107 | 55 | 29 | 23 |
| NPRA—Alaska(1) | 93 | 70 | - | 23 |
| Caldita/Barossa—Australia(1) | 77 | - | - | 77 |
| Middle Magdalena Basin—Colombia(1) | 31 | 31 | - | - |
| Limbayong—Malaysia(1) | 23 | 23 | - | - |
| Alpine Satellite—Alaska(2) | 22 | - | - | 22 |
| Bohai—China(2) | 19 | 19 | - | - |
| Kamunsu East—Malaysia(2) | 19 | 19 | - | - |
| NC 98—Libya(2) | 15 | 11 | - | 4 |
| Sunrise—Australia(2) | 13 | - | - | 13 |
| Other of $10 million or less each(1)(2) | 43 | 25 | 3 | 15 |
| Total | $ 931 | 648 | 58 | 225 |

*(1)Additional appraisal wells planned.*
*(2)Appraisal drilling complete; costs being incurred to assess development.*

In line with our July 2015 announcement of plans to reduce future deepwater exploration spending, we recognized before-tax cancellation costs of $335 million and wrote off $48 million of before-tax capitalized rig costs in relation to the termination of our Gulf of Mexico deepwater drillship contract with Ensco in the Lower 48 segment in the third quarter of 2015. In July 2016, we entered into an agreement to terminate our final Gulf of Mexico deepwater drillship contract. The drillship, used to drill our operated deepwater well inventory in the Gulf of Mexico through April 2016, was contracted on a shared, three-year term. Accordingly, we recorded before-tax rig cancellation charges and third party costs of $146 million in our Lower 48 segment in 2016. These charges are included in the “Exploration expenses” line on our consolidated income statement.

In February 2017, we reached a settlement agreement on our contract for the Athena drilling rig, initially secured for our four-well commitment program in Angola. As a result of the cancellation, we will recognize a before-tax charge of $43 million net in the first quarter of 2017.

**Note 9—Impairments**

During 2016, 2015 and 2014, we recognized the following before-tax impairment charges:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2016** | 2015 | 2014 |
| Alaska | **$** | **1** | 10 | 59 |
| Lower 48 | | **149** | (2) | 208 |
| Canada | | **88** | 4 | 38 |
| Europe and North Africa | | **(160)** | 724 | 541 |
| Asia Pacific and Middle East | | **44** | 1,508 | 7 |
| Corporate | | **17** | 1 | 3 |
| | **$** | **139** | 2,245 | 856 |

<u>2016</u>
In Lower 48, we recorded impairments of $149 million primarily due to cancelled projects associated with plan of development changes for Eagle Ford infrastructure, as well as lower natural gas prices and increased asset retirement obligation estimates.

In Canada, we recorded impairments of $88 million mainly due to plan of development changes, as well as certain developed properties, which were classified as held for sale, being written down to fair value less costs to sell.

In Europe, we recorded a credit to impairment of $160 million, primarily in the United Kingdom, due to decreased asset retirement obligation estimates on fields that are nearing the end of life and were impaired in prior years, partly offset by asset impairments due to lower natural gas prices in the United Kingdom.

In Asia Pacific and Middle East, we recorded impairments of $44 million, mainly due to the write-down to fair value less costs to sell of our developed properties in Block B, offshore Indonesia, in the third quarter of 2016.

In Corporate, we recorded impairments of $17 million due to cancelled projects in our Houston and Bartlesville offices.

The charges discussed below, within this section, are included in the "Exploration expenses" line on our consolidated income statement and are not reflected in the table above.

Charges recorded in exploration expenses in 2016 were related to our decision announced in 2015 to reduce deepwater exploration spending.

In our Lower 48 segment, we recorded a $203 million before-tax impairment for the associated carrying value of our Gibson and Tiber undeveloped leaseholds in deepwater Gulf of Mexico. Additionally, we recorded a $95 million before-tax impairment for the associated carrying value of capitalized undeveloped leasehold costs of the Melmar prospect and a $79 million impairment, primarily as a result of changes in the estimated market value following the completion of marketing efforts.

In our Canada segment, we recorded before-tax unproved property impairments of $31 million, primarily due to decisions to discontinue further testing of undeveloped leaseholds.

<u>2015</u>
See the "APLNG" section of Note 7—Investments, Loans and Long-Term Receivables, for information on the impairment of our APLNG investment included within the Asia Pacific and Middle East segment.

In Europe, we recorded impairments of $724 million, primarily in the United Kingdom as a result of lower natural gas prices and increases to asset retirement obligations.

The charges discussed below, within this section, are included in the "Exploration expenses" line on our consolidated income statement and are not reflected in the table above.

In our Other International segment, we decided not to pursue further evaluation of our Block 36 and Block 37 leases in Angola due to lack of commerciality of wells. Accordingly, we recorded impairments of $377 million and $116 million, respectively, for the associated carrying values of capitalized undeveloped leasehold costs.

In our Lower 48 segment, we decided not to conduct further activity on certain Gulf of Mexico leases, given our strategic plans to reduce deepwater exploration spending, and accordingly recorded impairments of $399 million for the associated carrying value of certain capitalized undeveloped leasehold costs.

In our Asia Pacific and Middle East segment, we decided to relinquish our Palangkaraya PSC in Indonesia. Accordingly, we recorded an impairment of $105 million for the associated carrying values of capitalized undeveloped leasehold cost.

In our Alaska segment, we recorded an impairment of $575 million for the associated carrying value of capitalized undeveloped leasehold cost in the Chukchi Sea in Alaska.

In our Canada segment, we recorded an impairment of $102 million for the Duvernay, Thornbury, Saleski and Crow Lake areas driven primarily by the lack of commerciality of wells.

*2014*

In Alaska, we recorded impairments of $59 million, primarily due to a cancelled project.

In our Lower 48 segment, we recorded impairments of $208 million, primarily as a result of reduced volume forecasts for an onshore field, as well as an LNG-related pipeline.

We recorded impairments of $38 million in our Canada segment, primarily due to reduced volume forecasts and lower natural gas prices.

In Europe, we recorded impairments of $541 million, mainly due to reduced volume forecasts, increases in the ARO and lower natural gas prices for properties in the United Kingdom which are nearing the end of their useful lives.

The charges discussed below, within this section, are included in the "Exploration expenses" line on our consolidated income statement and are not reflected in the table above.

In our Lower 48 segment, we recorded unproved property impairments of $239 million, primarily due to decisions to discontinue further testing of the undeveloped leaseholds.

Additionally, we decided not to pursue future development of the Amauligak discovery. Accordingly, we recorded a $145 million property impairment for the carrying value of capitalized undeveloped leasehold costs associated with our Amauligak, Arctic Islands and other Beaufort properties located offshore Canada.

**Note 10—Asset Retirement Obligations and Accrued Environmental Costs**

Asset retirement obligations and accrued environmental costs at December 31 were:

| | Millions of Dollars | |
|---|---|---|
| | **2016** | 2015 |
| Asset retirement obligations | $ **8,405** | 9,911 |
| Accrued environmental costs | **247** | 258 |
| Total asset retirement obligations and accrued environmental costs | **8,652** | 10,169 |
| Asset retirement obligations and accrued environmental costs due within one year* | **(227)** | (589) |
| Long-term asset retirement obligations and accrued environmental costs | $ **8,425** | 9,580 |

**Classified as a current liability on the balance sheet under "Other accruals."*

**Asset Retirement Obligations**

We record the fair value of a liability for an asset retirement obligation when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize the associated asset retirement cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time, the liability increases for the change in its present value, while the capitalized cost depreciates over the useful life of the related asset.

We have numerous asset retirement obligations we are required to perform under law or contract once an asset is permanently taken out of service. Most of these obligations are not expected to be paid until several years, or decades, in the future and will be funded from general company resources at the time of removal. Our largest individual obligations involve plugging and abandonment of wells and removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska.

During 2016 and 2015, our overall asset retirement obligation changed as follows:

| | Millions of Dollars | |
|---|---|---|
| | **2016** | 2015 |
| Balance at January 1 | $ **9,911** | 10,939 |
| Accretion of discount | **420** | 480 |
| New obligations | **180** | 135 |
| Changes in estimates of existing obligations | **(1,197)** | 267 |
| Spending on existing obligations | **(314)** | (437) |
| Property dispositions | **(150)** | (726) |
| Foreign currency translation | **(464)** | (747) |
| Other | **19** | - |
| Balance at December 31 | $ **8,405** | 9,911 |

**Accrued Environmental Costs**

Total accrued environmental costs at December 31, 2016 and 2015, were $247 million and $258 million, respectively.

We had accrued environmental costs of $183 million and $184 million at December 31, 2016 and 2015, respectively, related to remediation activities in the United States and Canada. We had also accrued in Corporate and Other $51 million and $57 million of environmental costs associated with sites no longer in operation at December 31, 2016 and 2015, respectively. In addition, $13 million and $17 million were included at both December 31, 2016 and 2015, respectively, where the company has been named a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act, or similar state laws. Accrued environmental liabilities are expected to be paid over periods extending up to 30 years.

Expected expenditures for environmental obligations acquired in various business combinations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $92 million at December 31, 2016. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $9 million in 2017, $12 million in 2018, $8 million in 2019, $5 million in 2020, $4 million in 2021, and $110 million for all future years after 2021.

## Note 11—Debt

Long-term debt at December 31 was:

| | Millions of Dollars | |
|---|---|---|
| | **2016** | 2015 |
| 9.125% Debentures due 2021 | $ **150** | 150 |
| 8.20% Debentures due 2025 | **150** | 150 |
| 8.125% Notes due 2030 | **600** | 600 |
| 7.9% Debentures due 2047 | **100** | 100 |
| 7.8% Debentures due 2027 | **300** | 300 |
| 7.65% Debentures due 2023 | **88** | 88 |
| 7.40% Notes due 2031 | **500** | 500 |
| 7.375% Debentures due 2029 | **92** | 92 |
| 7.25% Notes due 2031 | **500** | 500 |
| 7.20% Notes due 2031 | **575** | 575 |
| 7% Debentures due 2029 | **200** | 200 |
| 6.95% Notes due 2029 | **1,549** | 1,549 |
| 6.875% Debentures due 2026 | **67** | 67 |
| 6.65% Debentures due 2018 | **297** | 297 |
| 6.50% Notes due 2039 | **2,750** | 2,750 |
| 6.00% Notes due 2020 | **1,000** | 1,000 |
| 5.951% Notes due 2037 | **645** | 645 |
| 5.95% Notes due 2036 | **500** | 500 |
| 5.95% Notes due 2046 | **500** | - |
| 5.90% Notes due 2032 | **505** | 505 |
| 5.90% Notes due 2038 | **600** | 600 |
| 5.75% Notes due 2019 | **2,250** | 2,250 |
| 5.625% Notes due 2016 | **-** | 1,250 |
| 5.20% Notes due 2018 | **500** | 500 |
| 4.95% Notes due 2026 | **1,250** | - |
| 4.30% Notes due 2044 | **750** | 750 |
| 4.20% Notes due 2021 | **1,250** | - |
| 4.15% Notes due 2034 | **500** | 500 |
| 3.35% Notes due 2024 | **1,000** | 1,000 |
| 3.35% Notes due 2025 | **500** | 500 |
| 2.875% Notes due 2021 | **750** | 750 |
| 2.4% Notes due 2022 | **1,000** | 1,000 |
| 2.2% Notes due 2020 | **500** | 500 |
| 1.5% Notes due 2018 | **750** | 750 |
| 1.05% Notes due 2017 | **1,000** | 1,000 |
| Floating rate term loan due 2019 at 1.94% – 2.31% during 2016 | **1,450** | - |
| Floating rate notes due 2018 at 0.69% – 1.24% during 2016 and 0.61% – 0.69% during 2015 | **250** | 250 |
| Floating rate notes due 2022 at 1.26% – 1.81% during 2016 and 1.18% – 1.26% during 2015 | **500** | 500 |
| Commercial paper at 0.16% – 0.80% during 2015 | **-** | 803 |
| Industrial Development Bonds due 2016 through 2038 at 0.01% – 0.91% during 2016 and 0.01% – 0.13% during 2015 | **18** | 18 |
| Marine Terminal Revenue Refunding Bonds due 2031 at 0.01% – 0.95% during 2016 and 0.01% – 0.14% during 2015 | **265** | 265 |
| Other | **24** | 24 |
| Debt at face value | **26,175** | 23,778 |
| Capitalized leases | **852** | 818 |
| Net unamortized premiums, discounts and debt issuance costs | **248** | 284 |
| Total debt | **27,275** | 24,880 |
| Short-term debt | **(1,089)** | (1,427) |
| Long-term debt | $ **26,186** | 23,453 |

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2017 through 2021 are: $1,089 million, $1,894 million, $3,784 million, $1,593 million and $2,235 million, respectively.

In the first quarter of 2016, we reduced our revolving credit facility, expiring in June 2019, from $7.0 billion to $6.75 billion. Our revolving credit facility may be used for direct bank borrowings, for the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper programs. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the United States. The agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

We have two commercial paper programs supported by our $6.75 billion revolving credit facility: the ConocoPhillips $6.25 billion program, primarily a funding source for short-term working capital needs, and the ConocoPhillips Qatar Funding Ltd. $500 million program, which is used to fund commitments relating to QG3. Commercial paper maturities are generally limited to 90 days.

At both December 31, 2016 and 2015, we had no direct outstanding borrowings under the revolving credit facility, with no letters of credit as of December 31, 2016 and 2015. Under the ConocoPhillips Qatar Funding Ltd. commercial paper program, no commercial paper was outstanding at December 31, 2016, compared with $803 million at December 31, 2015. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.75 billion in borrowing capacity under our revolving credit facility at December 31, 2016.

In March 2016, we issued notes consisting of:

- The $1,250 million of 4.20% Notes due 2021.
- The $1,250 million of 4.95% Notes due 2026.
- The $500 million of 5.95% Notes due 2046.

In addition, on March 18, 2016, we entered into a $1,600 million three-year senior unsecured term loan facility. In December 2016, an early repayment of $150 million reduced the loan to $1,450 million. We have the right at any time and from time to time to prepay the term loan, in whole or in part, without premium or penalty upon notice to the Administrative Agent. Borrowings will accrue interest at a base rate or, for certain Eurodollar borrowings, the London Interbank Offered Rate (LIBOR), in each case plus a margin that is set based on our corporate credit ratings. The applicable margin for loans bearing interest based on the base rate ranges from 0.50% to 1.00% and the applicable margin for loans bearing interest based on LIBOR ranges from 1.50% to 2.00%. Based on our current corporate credit ratings, the applicable margin for loans accruing interest at the base rate is 0.50% and the applicable margin for loans accruing interest at LIBOR is 1.50%.

The term loan facility contains customary covenants regarding, among other matters, material compliance with laws and restrictions against certain consolidations, mergers and asset sales and creation of certain liens on our assets and consolidated subsidiaries. The term loan facility also contains financial covenants including a total debt to capitalization ratio, excluding the impacts of certain noncash impairments and foreign currency translation adjustments as defined in the Term Loan Agreement, which may not exceed 65 percent. At December 31, 2016, we were in compliance with this covenant.

The term loan facility includes customary events of default (subject to specified cure periods, materiality qualifiers and exceptions), including the failure to pay any interest, principal or fees when due, the failure to perform or the violation of any covenant contained in the term loan facility, the making of materially inaccurate or false representations or warranties, a default on certain material indebtedness, insolvency or bankruptcy, a change of control and the occurrence of material Employee Retirement Income Security Act of 1974 (ERISA) events and certain judgments against us or our material subsidiaries.

The net proceeds of the notes and term loan will be used for general corporate purposes.

On October 17, 2016, the $1,250 million 5.625% Notes due 2016 were repaid at maturity.

At both December 31, 2016 and 2015, we had $283 million of certain variable rate demand bonds (VRDBs) outstanding with maturities ranging through 2035. The VRDBs are redeemable at the option of the bondholders on any business day. The VRDBs are included in the "Long-term debt" line on our consolidated balance sheet.

During 2013, a lease of a semi-submersible floating production system (FPS) commenced for the Gumusut development, located in Malaysia, in which we are a co-venturer. The FPS lease provides for an initial noncancelable term of 15 years, a subsequent 5-year cancelable term with no required lease payments, and an additional 5-year term with terms and conditions to be agreed at a later date. The lease has no ongoing purchase options or escalation clauses. Adjustments to provisional contingent rental payments may occur due to the finalization of actual commissioning costs. The lease does not impose any significant restrictions concerning dividends, debt or further leasing activities.

A capital lease asset and capital lease obligation were recognized for our proportionate interest in the FPS of $906 million, based on the present value of the future minimum lease payments using our before-tax incremental borrowing rate of 3.58 percent for debt with similar terms. Unitization of the Gumusut development with Brunei was recorded during the fourth quarter of 2015 and reduced our proportionate interest in the FPS from 33 percent to 29 percent. The net carrying value of the capital lease asset was approximately $540 million and $707 million as of December 31, 2016 and December 31, 2015, respectively. The capital lease asset is being depreciated over a period consistent with the estimated proved reserves of Gumusut using the unit-of-production method with the associated depreciation included in the "Depreciation, depletion and amortization" line on our consolidated income statement. As of December 31, 2016 and December 31, 2015, accumulated depreciation of the capital lease asset amounted to approximately $268 million and $122 million, respectively.

At December 31, 2016, future minimum payments due under capital leases were:

| | Millions of Dollars |
|---|---|
| 2017 | $ 121 |
| 2018 | 102 |
| 2019 | 102 |
| 2020 | 103 |
| 2021 | 88 |
| Remaining years | 590 |
| Total | 1,106 |
| Less: portion representing imputed interest | (254) |
| Capital lease obligations | $ 852 |

## Note 12—Guarantees

At December 31, 2016, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability, at inception, for the fair value of our obligation as a guarantor for newly issued or modified guarantees. Unless the carrying amount of the liability is noted below, we have not recognized a liability because the fair value of the obligation is immaterial. In addition, unless otherwise stated, we are not currently performing with any significance under the guarantee and expect future performance to be either immaterial or have only a remote chance of occurrence.

### APLNG Guarantees

At December 31, 2016, we had outstanding multiple guarantees in connection with our 37.5 percent ownership interest in APLNG. The following is a description of the guarantees with values calculated utilizing December 2016 exchange rates:

- We have guaranteed APLNG's performance with regard to a construction contract executed in connection with APLNG's issuance of the Train 1 and Train 2 Notices to Proceed. We estimate the remaining term of this guarantee is one year. Our maximum potential amount of future payments related to this guarantee is approximately $10 million and would become payable if APLNG cancels the applicable construction contract and does not perform with respect to the amounts owed to the contractor.

- We have issued a construction completion guarantee related to the third-party project financing secured by APLNG. Our guarantee of the project financing will be released upon meeting certain completion tests with milestones which we estimate should occur in 2017. In October 2016, we reached financial completion for Train 1, releasing a portion of our guarantee. Our maximum exposure at December 31, 2016, is $1.3 billion based upon our pro-rata share of the facility used at that date, which could be payable if completion of the project is not achieved. At December 31, 2016, the carrying value of this guarantee is approximately $46 million.

- During the third quarter of 2016, we issued a guarantee for our pro-rata portion of the funds in a project finance reserve account. We estimate the remaining term of this guarantee is 13 years. Our maximum exposure under this guarantee is approximately $60 million and may become payable if an enforcement action is commenced by the project finance lenders against APLNG. At December 31, 2016, the carrying value of this guarantee is approximately $9 million.

- In conjunction with our original purchase of an ownership interest in APLNG from Origin Energy in October 2008, we agreed to reimburse Origin Energy for our share of the existing contingent liability arising under guarantees of an existing obligation of APLNG to deliver natural gas under several sales agreements with remaining terms of 1 to 25 years. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $1.0 billion ($1.7 billion in the event of intentional or reckless breach) and would become payable if APLNG fails to meet its obligations under these agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, would only be triggered if APLNG does not have enough natural gas to meet these sales commitments and if the co-venturers do not make necessary equity contributions into APLNG.

- We have guaranteed the performance of APLNG with regard to certain other contracts executed in connection with the project's continued development. The guarantees have remaining terms of up to 29 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $160 million and would become payable if APLNG does not perform.

### Other Guarantees

We have other guarantees with maximum future potential payment amounts totaling approximately $540 million, which consist primarily of a guarantee of the residual value of a leased office building, guarantees of the residual value of leased corporate aircraft, and a guarantee for our portion of a joint venture's project finance reserve accounts. These guarantees have remaining terms of up to six years and would become payable if, upon sale, certain asset values are lower than guaranteed amounts, business conditions decline at guaranteed entities, or as a result of nonperformance of contractual terms by guaranteed parties.

**Indemnifications**

Over the years, we have entered into agreements to sell ownership interests in certain corporations, joint ventures and assets that gave rise to qualifying indemnifications. These agreements include indemnifications for taxes, environmental liabilities, employee claims and litigation. The terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications at December 31, 2016, was approximately $100 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the recorded carrying amount at December 31, 2016, were approximately $40 million of environmental accruals for known contamination that are included in the "Asset retirement obligations and accrued environmental costs" line on our consolidated balance sheet. For additional information about environmental liabilities, see Note 13—Contingencies and Commitments.

On April 30, 2012, the separation of our downstream business was completed, creating two independent energy companies: ConocoPhillips and Phillips 66. In connection with the separation, we entered into an Indemnification and Release Agreement, which provides for cross-indemnities between Phillips 66 and us and established procedures for handling claims subject to indemnification and related matters. We evaluated the impact of the indemnifications given and the Phillips 66 indemnifications received as of the separation date and concluded those fair values were immaterial.

On March 1, 2015, a supplier to one of the refineries included in Phillips 66 as part of the separation of our downstream business formally registered Phillips 66 as a party to the supply agreement, thereby triggering a guarantee we provided at the time of separation. Our maximum potential liability for future payments under this guarantee, which would become payable if Phillips 66 does not perform its contractual obligations under the supply agreement, is approximately $1.4 billion. At December 31, 2016, the carrying value of this guarantee is approximately $98 million and the remaining term is eight years. Because Phillips 66 has indemnified us for losses incurred under this guarantee, we have recorded an indemnification asset from Phillips 66 of approximately $98 million. The recorded indemnification asset amount represents the estimated fair value of the guarantee; however, if we are required to perform under the guarantee, we would expect to recover from Phillips 66 any amounts in excess of that value, provided Phillips 66 is a going concern.

## Note 13—Contingencies and Commitments

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. With respect to income tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. See Note 19—Income Taxes, for additional information about income tax-related contingencies.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

**Environmental**
We are subject to international, federal, state and local environmental laws and regulations. When we prepare our consolidated financial statements, we record accruals for environmental liabilities based on management's best estimates, using all information that is available at the time. We measure estimates and base liabilities on currently available facts, existing technology, and presently enacted laws and regulations, taking into account stakeholder and business considerations. When measuring environmental liabilities, we also consider our prior experience in remediation of contaminated sites, other companies' cleanup experience, and data released by the U.S. Environmental Protection Agency (EPA) or other organizations. We consider unasserted claims in our determination of environmental liabilities, and we accrue them in the period they are both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for other sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all cleanup costs related to any site at which we have been designated as a potentially responsible party. We have been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the agency concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, we consider this inability in estimating our potential liability, and we adjust our accruals accordingly. As a result of various acquisitions in the past, we assumed certain environmental obligations. Some of these environmental obligations are mitigated by indemnifications made by others for our benefit, and some of the indemnifications are subject to dollar limits and time limits.

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state and international sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. See Note 10—Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

**Legal Proceedings**
We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, personal injury, and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required.

**Other Contingencies**
We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at December 31, 2016, we had performance obligations secured by letters of credit of $304 million (issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, commercial activities and services incident to the ordinary conduct of business.

In 2007, we announced we had been unable to reach agreement with respect to our migration to an *empresa mixta* structure mandated by the Venezuelan government's Nationalization Decree. As a result, Venezuela's national oil company, Petróleos de Venezuela S.A. (PDVSA), or its affiliates, directly assumed control over ConocoPhillips' interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, we filed a request for international arbitration on November 2, 2007, with the World Bank's International Centre for Settlement of Investment Disputes (ICSID). An arbitration hearing was held before an ICSID tribunal during the summer of 2010. On September 3, 2013, an ICSID arbitration tribunal held that Venezuela unlawfully expropriated ConocoPhillips' significant oil investments in June 2007. On January 17, 2017, the Tribunal reconfirmed the decision that the expropriation was unlawful. A separate arbitration phase is currently proceeding to determine the damages owed to ConocoPhillips for Venezuela's actions. Separate arbitrations for contractual compensation against PDVSA are also pending before an International Chamber of Commerce (ICC) arbitration tribunal. In addition, ConocoPhillips brought fraudulent transfer actions in the U.S. District Court of Delaware, alleging that PDVSA has taken actions to improperly expatriate assets from the United States to Venezuela in an effort to avoid judgment creditors.

In 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before ICSID against The Republic of Ecuador, as a result of the newly enacted Windfall Profits Tax Law and government-mandated renegotiation of our production sharing contracts. Despite a restraining order issued by the ICSID tribunal, Ecuador confiscated the crude oil production of Burlington and its co-venturer and sold the seized crude oil. In 2009, Ecuador took over operations in Blocks 7 and 21, fully expropriating our assets. In June 2010, the ICSID tribunal concluded it has jurisdiction to hear the expropriation claim. On April 24, 2012, Ecuador filed supplemental counterclaims asserting environmental damages, which we believe are not material. The ICSID tribunal issued a decision on liability on December 14, 2012, in favor of Burlington, finding that Ecuador's seizure of Blocks 7 and 21 was an unlawful expropriation in violation of the Ecuador-U.S. Bilateral Investment Treaty. An additional arbitration phase to determine the damages owed to ConocoPhillips for Ecuador's actions and to address Ecuador's counterclaims is complete. In February 2017, the tribunal unanimously awarded Burlington $380 million for Ecuador's unlawful expropriation and breach of the U.S.-Ecuador bilateral investment treaty. The tribunal also issued a separate decision finding Ecuador to be entitled to $42 million for limited environmental and infrastructure impacts associated with the operations of Burlington and its co-venturer. Ecuador recently filed a request for annulment of this decision with ICSID. The schedule for the annulment process has not yet been set.

In December 2016, ConocoPhillips Angola filed a notice of arbitration against Sonangol E.P. under the Block 36 Production Sharing Contract relating to disputes arising thereunder. The arbitration will be conducted under the United Nations Commission on International Trade Laws (UNCITRAL) rules using a three person tribunal.

**Long-Term Throughput Agreements and Take-or-Pay Agreements**
We have certain throughput agreements and take-or-pay agreements in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the company's business. The aggregate amounts of estimated payments under these various agreements are: 2017—$24 million; 2018—$20 million; 2019—$7 million; 2020—$7 million; 2021—$7 million; and 2022 and after—$75 million. Total payments under the agreements were $42 million in 2016, $27 million in 2015 and $127 million in 2014.

## Note 14—Derivative and Financial Instruments

We use futures, forwards, swaps and options in various markets to meet our customer needs and capture market opportunities. Our commodity business primarily consists of natural gas, crude oil, bitumen, LNG and natural gas liquids.

Our derivative instruments are held at fair value on our consolidated balance sheet. Where these balances have the right of setoff, they are presented on a net basis. Related cash flows are recorded as operating activities on our consolidated statement of cash flows. On our consolidated income statement, realized and unrealized gains and losses are recognized either on a gross basis if directly related to our physical business or a net basis if held for trading. Gains and losses related to contracts that meet and are designated with the normal purchase normal sale exception are recognized upon settlement. We generally apply this exception to eligible crude contracts. We do not use hedge accounting for our commodity derivatives.

The following table presents the gross fair values of our commodity derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

| | Millions of Dollars | |
|---|---|---|
| | **2016** | 2015 |
| **Assets** | | |
| Prepaid expenses and other current assets | $ **268** | 768 |
| Other assets | **44** | 60 |
| **Liabilities** | | |
| Other accruals | **300** | 754 |
| Other liabilities and deferred credits | **34** | 46 |

The gains (losses) from commodity derivatives incurred, and the line items where they appear on our consolidated income statement were:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| Sales and other operating revenues | $ **(198)** | 231 | 523 |
| Other income | **(1)** | 2 | 1 |
| Purchased commodities | **161** | (201) | (458) |

The table below summarizes our material net exposures resulting from outstanding commodity derivative contracts:

| | Open Position Long/(Short) | |
|---|---|---|
| | **2016** | 2015 |
| **Commodity** | | |
| Natural gas and power (billions of cubic feet equivalent) | | |
| Fixed price | **(31)** | (14) |
| Basis | **2** | (17) |

**Foreign Currency Exchange Derivatives**
We have foreign currency exchange rate risk resulting from international operations. Our foreign currency exchange derivative activity primarily relates to managing our cash-related and foreign currency exchange rate exposures, such as firm commitments for capital programs or local currency tax payments, dividends, and cash returns from net investments in foreign affiliates. We do not elect hedge accounting on our foreign currency exchange derivatives.

The following table presents the gross fair values of our foreign currency exchange derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

| | Millions of Dollars | |
|---|---|---|
| | **2016** | 2015 |
| **Assets** | | |
| Prepaid expenses and other current assets | **$ 1** | 47 |
| **Liabilities** | | |
| Other accruals | **168** | 8 |

The (gains) losses from foreign currency exchange derivatives incurred, and the line item where they appear on our consolidated income statement were:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| Foreign currency transaction (gains) losses | **$ 247** | (33) | 3 |

We had the following net notional position of outstanding foreign currency exchange derivatives:

| | | In Millions Notional Currency | |
|---|---|---|---|
| | | **2016** | 2015 |
| **Foreign Currency Exchange Derivatives** | | | |
| Sell U.S. dollar, buy other currencies* | USD | **13** | 347 |
| Buy U.S. dollar, sell other currencies** | USD | **25** | 20 |
| Buy British pound, sell other currencies*** | GBP | **1,069** | 567 |
| Sell British pound, buy Norwegian krone | GBP | **51** | - |

**Primarily Canadian dollar, Norwegian krone and British pound.*
***Primarily Canadian dollar and British pound.*
****Primarily Canadian dollar and Euro.*

**Financial Instruments**
We have certain financial instruments on our consolidated balance sheet related to interest-bearing time deposits and commercial paper. These held-to-maturity financial instruments are included in "Cash and cash equivalents" on our consolidated balance sheet if the maturities at the time we made the investments were 90 days or less; otherwise, these investments are included in "Short-term investments" on our consolidated balance sheet.

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | Carrying Amount | | | |
| | Cash and Cash Equivalents | | Short-Term Investments | |
| | **2016** | 2015 | **2016** | 2015 |
| **Cash** | $ **623** | 528 | **-** | - |
| **Time deposits** | | | | |
| Remaining maturities from 1 to 90 days | **2,987** | 1,840 | **39** | - |
| Remaining maturities from 91 to 180 days | **-** | - | **11** | - |
| | $ **3,610** | 2,368 | **50** | - |

**Credit Risk**
Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalents, short-term investments, over-the-counter (OTC) derivative contracts and trade receivables. Our cash equivalents and short-term investments are placed in high-quality commercial paper, money market funds, government debt securities and time deposits with major international banks and financial institutions.

The credit risk from our OTC derivative contracts, such as forwards and swaps, derives from the counterparty to the transaction. Individual counterparty exposure is managed within predetermined credit limits and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant nonperformance. We also use futures, swaps and option contracts that have a negligible credit risk because these trades are cleared with an exchange clearinghouse and subject to mandatory margin requirements until settled; however, we are exposed to the credit risk of those exchange brokers for receivables arising from daily margin cash calls, as well as for cash deposited to meet initial margin requirements.

Our trade receivables result primarily from our petroleum operations and reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less, and we continually monitor this exposure and the creditworthiness of the counterparties. We do not generally require collateral to limit the exposure to loss; however, we will sometimes use letters of credit, prepayments and master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to us, as these agreements permit the amounts owed by us or owed to others to be offset against amounts due to us.

Certain of our derivative instruments contain provisions that require us to post collateral if the derivative exposure exceeds a threshold amount. We have contracts with fixed threshold amounts and other contracts with variable threshold amounts that are contingent on our credit rating. The variable threshold amounts typically decline for lower credit ratings, while both the variable and fixed threshold amounts typically revert to zero if we fall below investment grade. Cash is the primary collateral in all contracts; however, many also permit us to post letters of credit as collateral, such as transactions administered through the New York Mercantile Exchange.

The aggregate fair value of all derivative instruments with such credit risk-related contingent features that were in a liability position on December 31, 2016 and December 31, 2015, was $42 million and $158 million, respectively. For these instruments, no collateral was posted as of December 31, 2016, and $2 million of collateral was posted as of December 31, 2015. If our credit rating had been downgraded below investment grade on December 31, 2016, we would be required to post $42 million of additional collateral, either with cash or letters of credit.

**Note 15—Fair Value Measurement**

We carry a portion of our assets and liabilities at fair value that are measured at a reporting date using an exit price (i.e., the price that would be received to sell an asset or paid to transfer a liability) and disclosed according to the quality of valuation inputs under the following hierarchy:

- Level 1: Quoted prices (unadjusted) in an active market for identical assets or liabilities.
- Level 2: Inputs other than quoted prices that are directly or indirectly observable.
- Level 3: Unobservable inputs that are significant to the fair value of assets or liabilities.

The classification of an asset or liability is based on the lowest level of input significant to its fair value. Those that are initially classified as Level 3 are subsequently reported as Level 2 when the fair value derived from unobservable inputs is inconsequential to the overall fair value, or if corroborated market data becomes available. Assets and liabilities initially reported as Level 2 are subsequently reported as Level 3 if corroborated market data is no longer available. Transfers occur at the end of the reporting period. There were no material transfers in or out of Level 1 during 2016 or 2015.

**Recurring Fair Value Measurement**
Financial assets and liabilities reported at fair value on a recurring basis primarily include commodity derivatives. Level 1 derivative assets and liabilities primarily represent exchange-traded futures and options that are valued using unadjusted prices available from the underlying exchange. Level 2 derivative assets and liabilities primarily represent OTC swaps, options and forward purchase and sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data. Level 3 derivative assets and liabilities consist of OTC swaps, options and forward purchase and sale contracts where a significant portion of fair value is calculated from underlying market data that is not readily available. The derived value uses industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management's best estimate of fair value. Level 3 activity was not material for all periods presented.

The following table summarizes the fair value hierarchy for gross financial assets and liabilities (i.e., unadjusted where the right of setoff exists for commodity derivatives accounted for at fair value on a recurring basis):

| | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **December 31, 2016** | | | | December 31, 2015 | | | |
| | **Level 1** | **Level 2** | **Level 3** | **Total** | Level 1 | Level 2 | Level 3 | Total |
| **Assets** | | | | | | | | |
| Commodity derivatives | **$ 194** | **96** | **22** | **312** | 516 | 242 | 70 | 828 |
| Total assets | **$ 194** | **96** | **22** | **312** | 516 | 242 | 70 | 828 |
| **Liabilities** | | | | | | | | |
| Commodity derivatives | **$ 207** | **105** | **22** | **334** | 515 | 273 | 12 | 800 |
| Total liabilities | **$ 207** | **105** | **22** | **334** | 515 | 273 | 12 | 800 |

The following table summarizes those commodity derivative balances subject to the right of setoff as presented on our consolidated balance sheet. We have elected to offset the recognized fair value amounts for multiple derivative instruments executed with the same counterparty in our financial statements when a legal right of offset exists.

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Gross Amounts Recognized | Gross Amounts Offset | Net Amounts Presented | Cash Collateral | Gross Amounts without Right of Setoff | Net Amounts |
| **December 31, 2016** | | | | | | |
| Assets | **$ 312** | **221** | **91** | **-** | **5** | **86** |
| Liabilities | **334** | **221** | **113** | **12** | **12** | **89** |
| December 31, 2015 | | | | | | |
| Assets | $ 828 | 600 | 228 | - | 8 | 220 |
| Liabilities | 800 | 600 | 200 | 1 | 11 | 188 |

At December 31, 2016 and December 31, 2015, we did not present any amounts gross on our consolidated balance sheet where we had the right of setoff.

**Non-Recurring Fair Value Measurement**

The following table summarizes the fair value hierarchy by major category for assets accounted for at fair value on a non-recurring basis:

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | | Fair Value Measurements Using | | |
| | Fair Value | Level 1 Inputs | Level 3 Inputs | Before-Tax Loss |
| **Year ended December 31, 2016** | | | | |
| Net PP&E (held for use) | | | | |
| March 31, 2016 | **$ 217** | **-** | **217** | **129** |
| June 30, 2016 | **23** | **-** | **23** | **53** |
| December 31, 2016 | **13** | **-** | **13** | **29** |
| Net PP&E (held for sale) | | | | |
| September 30, 2016 | **217** | **217** | **-** | **99** |
| Cost and equity method investments | | | | |
| December 31, 2016 | **90** | **4** | **86** | **40** |
| Year ended December 31, 2015 | | | | |
| Net PP&E (held for use) | | | | |
| March 31, 2015 | $ - | - | - | 9 |
| June 30, 2015 | 42 | - | 42 | 70 |
| September 30, 2015 | - | - | - | 7 |
| December 31, 2015 | 440 | - | 440 | 595 |
| Net PP&E (unproved property) | | | | |
| September 30, 2015 | 104 | - | 104 | 240 |
| Equity method investments | | | | |
| December 31, 2015 | 10,210 | - | 10,210 | 1,507 |

*Net PP&E (held for use)*
Net PP&E held for use is comprised of various producing properties impaired to their individual fair values less costs to sell. The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges and pricing service companies, costs, and a discount rate believed to be consistent with those used by principal market participants.

*Net PP&E (held for sale)*
Net PP&E held for sale was written down to fair value, less costs to sell. The fair value of each asset was determined by its negotiated selling price.

*Net PP&E (unproved property)*
Net PP&E unproved property is comprised of unproved leaseholds impaired to our best estimate of sales value less costs to sell.

*Equity Method Investments*
Certain cost and equity method investments were determined to have fair values below their carrying amounts, and the impairments were considered to be other than temporary under the guidance of FASB ASC Topic 323. An investment using Level 1 inputs was written down to fair value, less costs to sell, determined by its negotiated selling price. Investments using Level 3 inputs had fair values determined primarily by internal discounted cash flow models using estimates of future production, prices from futures exchanges and pricing service companies, costs, and a discount factor believed to be consistent with those used by principal market participants. During 2015, this primarily included our investment in APLNG, which was written down to its fair value of $10,185 million, resulting in a charge of $1,502 million before-tax. For additional information on APLNG, see Note 7—Investments, Loans and Long-Term Receivables.

**Reported Fair Values of Financial Instruments**
We used the following methods and assumptions to estimate the fair value of financial instruments:

- Cash and cash equivalents and short-term investments: The carrying amount reported on the balance sheet approximates fair value.
- Accounts and notes receivable (including long-term and related parties): The carrying amount reported on the balance sheet approximates fair value. The valuation technique and methods used to estimate the fair value of the current portion of fixed-rate related party loans is consistent with Loans and advances—related parties.
- Loans and advances—related parties: The carrying amount of floating-rate loans approximates fair value. The fair value of fixed-rate loan activity is measured using market observable data and is categorized as Level 2 in the fair value hierarchy. See Note 7—Investments, Loans and Long-Term Receivables, for additional information.
- Accounts payable (including related parties) and floating-rate debt: The carrying amount of accounts payable and floating-rate debt reported on the balance sheet approximates fair value.
- Fixed-rate debt: The estimated fair value of fixed-rate debt is measured using prices available from a pricing service that is corroborated by market data; therefore, these liabilities are categorized as Level 2 in the fair value hierarchy.

The following table summarizes the net fair value of financial instruments (i.e., adjusted where the right of setoff exists for commodity derivatives):

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | Carrying Amount | | Fair Value | |
| | **2016** | 2015 | **2016** | 2015 |
| **Financial assets** | | | | |
| Commodity derivatives | $ **91** | 228 | **91** | 228 |
| Total loans and advances—related parties | **701** | 808 | **701** | 808 |
| **Financial liabilities** | | | | |
| Total debt, excluding capital leases | **26,423** | 24,062 | **29,307** | 24,785 |
| Commodity derivatives | **101** | 199 | **101** | 199 |

*Commodity derivatives*
At December 31, 2016, commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $12 million of rights to reclaim cash collateral, respectively. At December 31, 2015, commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $1 million of rights to reclaim cash collateral, respectively.

**Note 16—Equity**

**Common Stock**
The changes in our shares of common stock, as categorized in the equity section of the balance sheet, were:

| | Shares | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| **Issued** | | | |
| Beginning of year | **1,778,226,388** | 1,773,583,368 | 1,768,169,906 |
| Distributed under benefit plans | **3,852,719** | 4,643,020 | 5,413,462 |
| End of year | **1,782,079,107** | 1,778,226,388 | 1,773,583,368 |
| | | | |
| **Held in Treasury** | | | |
| Beginning of year | **542,230,673** | 542,230,673 | 542,230,673 |
| Repurchase of common stock | **2,579,098** | - | - |
| End of year | **544,809,771** | 542,230,673 | 542,230,673 |

**Preferred Stock**
We have authorized 500 million shares of preferred stock, par value $.01 per share, none of which was issued or outstanding at December 31, 2016 or 2015.

**Noncontrolling Interests**
At December 31, 2016 and 2015, we had $252 million and $320 million outstanding, respectively, of equity in less-than-wholly owned consolidated subsidiaries held by noncontrolling interest owners. For both periods, the amounts were related to the Darwin LNG and Bayu-Darwin Pipeline operating joint ventures we control.

**Repurchase of Common Stock**
On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock over the next three years. Repurchase of shares began in November and totaled 2,579,098 shares at a cost of $126 million, through December 31, 2016.

**Note 17—Non-Mineral Leases**

The company primarily leases drilling equipment and office buildings, as well as ocean transport vessels, tugboats, barges, corporate aircraft, computers and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices, as well as renewal options and/or options to purchase the leased property for the fair market value at the end of the lease term. There are no significant restrictions imposed on us by the leasing agreements with regard to dividends, asset dispositions or borrowing ability. For additional information on leased assets under capital leases, see Note 11—Debt.

At December 31, 2016, future minimum rental payments due under noncancelable leases were:

| | Millions of Dollars |
|---|---|
| 2017 | $ 277 |
| 2018 | 238 |
| 2019 | 172 |
| 2020 | 390 |
| 2021 | 114 |
| Remaining years | 435 |
| Total | 1,626 |
| Less: income from subleases | (15) |
| Net minimum operating lease payments | $ 1,611 |

Operating lease rental expense for the years ended December 31 was:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| Total rentals | **$ 537** | 432 | 474 |
| Less: sublease rentals | **(8)** | (9) | (10) |
| | **$ 529** | 423 | 464 |

**Note 18—Employee Benefit Plans**

**Pension and Postretirement Plans**

An analysis of the projected benefit obligations for our pension plans and accumulated benefit obligations for our postretirement health and life insurance plans follows:

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Pension Benefits | | | | Other Benefits | |
| | **2016** | | 2015 | | **2016** | 2015 |
| | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| **Change in Benefit Obligation** | | | | | | |
| Benefit obligation at January 1 | **$ 3,772** | **3,321** | 4,387 | 3,984 | **352** | 716 |
| Service cost | **108** | **76** | 138 | 124 | **2** | 4 |
| Interest cost | **133** | **120** | 161 | 135 | **13** | 22 |
| Plan participant contributions | **-** | **3** | - | 5 | **24** | 21 |
| Plan amendments | **-** | **-** | - | - | **(27)** | (303) |
| Actuarial (gain) loss | **247** | **466** | (212) | (442) | **(14)** | (49) |
| Benefits paid | **(872)** | **(148)** | (729) | (162) | **(68)** | (63) |
| Curtailment | **14** | **10** | 27 | (43) | **3** | 8 |
| Settlement | **-** | **(46)** | - | - | **-** | - |
| Recognition of termination benefits | **14** | **1** | - | 68 | **-** | - |
| Foreign currency exchange rate change | **-** | **(358)** | - | (348) | **1** | (4) |
| Benefit obligation at December 31* | **$ 3,416** | **3,445** | 3,772 | 3,321 | **286** | 352 |
| **Accumulated benefit obligation portion of above at December 31:* | ***$ 3,246*** | ***3,067*** | *3,573* | *2,953* | | |
| **Change in Fair Value of Plan Assets** | | | | | | |
| Fair value of plan assets at January 1 | **$ 2,606** | **3,063** | 3,266 | 3,278 | **-** | - |
| Actual return on plan assets | **133** | **397** | (4) | 96 | **-** | - |
| Company contributions | **214** | **125** | 73 | 120 | **44** | 42 |
| Plan participant contributions | **-** | **3** | - | 5 | **24** | 21 |
| Benefits paid | **(872)** | **(148)** | (729) | (162) | **(68)** | (63) |
| Foreign currency exchange rate change | **-** | **(372)** | - | (274) | **-** | - |
| Fair value of plan assets at December 31 | **$ 2,081** | **3,068** | 2,606 | 3,063 | **-** | - |
| **Funded Status** | **$ (1,335)** | **(377)** | (1,166) | (258) | **(286)** | (352) |

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Pension Benefits | | | | Other Benefits | |
| | **2016** | | 2015 | | **2016** | 2015 |
| | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| **Amounts Recognized in the Consolidated Balance Sheet at December 31** | | | | | | |
| Noncurrent assets | **$ -** | **164** | - | 175 | **-** | - |
| Current liabilities | **(101)** | **(7)** | (99) | (34) | **(44)** | (45) |
| Noncurrent liabilities | **(1,234)** | **(534)** | (1,067) | (399) | **(242)** | (307) |
| Total recognized | **$ (1,335)** | **(377)** | (1,166) | (258) | **(286)** | (352) |
| **Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31** | | | | | | |
| Discount rate | **3.95 %** | **3.00** | 4.50 | 3.95 | **3.60** | 3.90 |
| Rate of compensation increase | **4.00** | **3.85** | 4.00 | 4.05 | **-** | - |
| **Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31** | | | | | | |
| Discount rate | **3.90 %** | **3.95** | 4.00 | 3.55 | **3.75** | 4.05 |
| Expected return on plan assets | **7.00** | **5.45** | 7.00 | 5.40 | **-** | - |
| Rate of compensation increase | **4.00** | **4.05** | 4.75 | 4.35 | **-** | - |

For both U.S. and international pensions, the overall expected long-term rate of return is developed from the expected future return of each asset class, weighted by the expected allocation of pension assets to that asset class. We rely on a variety of independent market forecasts in developing the expected rate of return for each class of assets.

Included in accumulated other comprehensive income (loss) at December 31 were the following before-tax amounts that had not been recognized in net periodic benefit cost:

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Pension Benefits | | | | Other Benefits | |
| | **2016** | | 2015 | | **2016** | 2015 |
| | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| Unrecognized net actuarial (gain) loss | **$ 748** | **479** | 773 | 273 | **(27)** | (18) |
| Unrecognized prior service cost (credit) | **4** | **(20)** | 9 | (30) | **(285)** | (292) |

| | | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|---|
| | | Pension Benefits | | | | Other Benefits | |
| | | **2016** | | 2015 | | **2016** | 2015 |
| | | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| **Sources of Change in Other Comprehensive Income (Loss)** | | | | | | | |
| Net gain (loss) arising during the period | $ | **(263)** | **(232)** | 61 | 490 | **14** | 41 |
| Amortization of (gain) loss included in net loss* | | **288** | **26** | 312 | 89 | **(5)** | 2 |
| Net change during the period | $ | **25** | **(206)** | 373 | 579 | **9** | 43 |
| | | | | | | | |
| Prior service credit (cost) arising during the period | $ | **-** | **(4)** | - | (2) | **27** | 303 |
| Amortization of prior service cost (credit) included in net loss | | **5** | **(6)** | 7 | (11) | **(34)** | (15) |
| Net change during the period | $ | **5** | **(10)** | 7 | (13) | **(7)** | 288 |

**Includes settlement losses recognized in 2016 and 2015.*

During the year ended December 31, 2016, there was an amendment to the U.S. other postretirement benefit plan. The benefit obligation decreased by $27 million for changes in the plan made to post-65 retiree medical benefits related to updated cost sharing assumption changes for retirees. The $27 million decrease in the benefit obligation resulted in a corresponding increase in other comprehensive income.

During the year ended December 31, 2015, there were amendments to the U.S. other postretirement benefit plan. The benefit obligation decreased by $303 million for changes in the plan made to retiree medical benefits. The $303 million decrease consists of $149 million related to the discontinuation of all company premium cost-sharing contributions to the post-65 retiree medical plan after December 31, 2025, $91 million related to updated cost sharing assumption changes for retirees, $49 million associated with excluding employees and retirees of Phillips 66 who were not enrolled in a ConocoPhillips retiree medical plan as of July 1, 2015, and $14 million associated with new participants in the post-65 retiree medical plan after December 31, 2015, no longer being eligible for any company premium cost-sharing contributions. The $303 million decrease in the benefit obligation resulted in a corresponding decrease in other comprehensive loss.

Included in accumulated other comprehensive income (loss) at December 31, 2016, were the following before-tax amounts that are expected to be amortized into net periodic benefit cost during 2017:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | Pension Benefits | | Other Benefits |
| | | U.S. | Int'l. | |
| Unrecognized net actuarial (gain) loss | $ | 75 | 48 | (3) |
| Unrecognized prior service cost (credit) | | 4 | (5) | (36) |

For our tax-qualified pension plans with projected benefit obligations in excess of plan assets, the projected benefit obligation, the accumulated benefit obligation, and the fair value of plan assets were $5,498 million, $5,145 million, and $4,208 million, respectively, at December 31, 2016, and $5,720 million, $5,314 million, and $4,759 million, respectively, at December 31, 2015.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $586 million and $496 million, respectively, at December 31, 2016, and were $639 million and $564 million, respectively, at December 31, 2015.

The components of net periodic benefit cost of all defined benefit plans are presented in the following table:

| | | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Pension Benefits | | | | | | Other Benefits | | |
| | | **2016** | | 2015 | | 2014 | | **2016** | 2015 | 2014 |
| | | **U.S.** | **Int'l.** | U.S. | Int'l. | U.S. | Int'l. | | | |
| **Components of Net Periodic Benefit Cost** | | | | | | | | | | |
| Service cost | **$** | **108** | **76** | 138 | 124 | 124 | 109 | **2** | 4 | 3 |
| Interest cost | | **133** | **120** | 161 | 135 | 165 | 166 | **13** | 22 | 29 |
| Expected return on plan assets | | **(149)** | **(147)** | (201) | (164) | (213) | (181) | **-** | - | - |
| Amortization of prior service cost (credit) | | **5** | **(6)** | 6 | (7) | 6 | (8) | **(34)** | (17) | (4) |
| Recognized net actuarial loss (gain) | | **86** | **26** | 115 | 82 | 77 | 57 | **(2)** | 2 | (3) |
| Settlements | | **202** | **-** | 197 | 7 | - | - | **-** | - | - |
| Curtailment (gain) loss | | **14** | **-** | 35 | (4) | - | - | **1** | 2 | - |
| Net periodic benefit cost | **$** | **399** | **69** | 451 | 173 | 159 | 143 | **(20)** | 13 | 25 |

We recognized pension settlement losses of $202 million in 2016 and $204 million in 2015 as lump-sum benefit payments from certain U.S. and international pension plans exceeded the sum of service and interest costs for those plans and led to recognition of settlement losses.

As part of the 2016 and 2015 restructuring programs, we concluded that actions taken during those years resulted in a significant reduction of future services of active employees primarily in the U.S. qualified pension plan and a U.S. nonqualified supplemental retirement plan. As a result, we recognized an increase in the benefit obligation and a proportionate share of prior service cost from other comprehensive income (loss) as curtailment losses of $15 million and $33 million during the years ended December 31, 2016 and 2015, respectively.

Also as part of the 2016 and 2015 restructuring programs in the U.S. and Europe, we recognized expense for special termination benefits of $15 million during the year ended December 31, 2016, consisting of $14 million in the U.S. and $1 million in Europe, and $124 million during the year ended December 31, 2015, consisting of $46 million in the U.S. and $78 million in Europe. Approximately 62 percent of the 2015 Europe amount was recovered from joint venture partners.

In determining net pension and other postretirement benefit costs, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. For net actuarial gains and losses, we amortize 10 percent of the unamortized balance each year.

We have multiple nonpension postretirement benefit plans for health and life insurance. The health care plans are contributory and subject to various cost sharing features, with participant and company contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the U.S. pre-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 6.50 percent in 2017 that declines to 5 percent by 2023. The measurement of the U.S. post-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 4 percent in 2017 that increases to 5 percent by 2018. A one-percentage-point change in the assumed health care cost trend rate would be immaterial to ConocoPhillips.

**Plan Assets**—We follow a policy of broadly diversifying pension plan assets across asset classes and individual holdings. As a result, our plan assets have no significant concentrations of credit risk. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. The target allocations for plan assets are 57 percent equity securities, 37 percent debt securities and 6 percent real estate. Generally, the plan investments are publicly traded, therefore minimizing liquidity risk in the portfolio.

The following is a description of the valuation methodologies used for the pension plan assets. There have been no changes in the methodologies used at December 31, 2016 and 2015.

- Fair values of equity securities and government debt securities categorized in Level 1 are primarily based on quoted market prices in active markets for identical assets and liabilities.
- Fair values of corporate debt securities, agency and mortgage-backed securities and government debt securities categorized in Level 2 are estimated using recently executed transactions and quoted market prices for similar assets and liabilities in active markets and for identical assets and liabilities in markets that are not active. If there have been no market transactions in a particular fixed income security, its fair value is calculated by pricing models that benchmark the security against other securities with actual market prices. When observable quoted market prices are not available, fair value is based on pricing models that use something other than actual market prices (e.g., observable inputs such as benchmark yields, reported trades and issuer spreads for similar securities), and these securities are categorized in Level 3 of the fair value hierarchy.
- Fair values of investments in common/collective trusts are determined by the issuer of each fund based on the fair value of the underlying assets.
- Fair values of mutual funds are based on quoted market prices, which represent the net asset value of shares held.
- Cash is valued at cost, which approximates fair value. Fair values of international cash equivalents categorized in Level 2 are valued using observable yield curves, discounting and interest rates. U.S. cash balances held in the form of short-term fund units that are redeemable at the measurement date are categorized as Level 2.
- Fair values of exchange-traded derivatives classified in Level 1 are based on quoted market prices. For other derivatives classified in Level 2, the values are generally calculated from pricing models with market input parameters from third-party sources.
- Fair values of insurance contracts are valued at the present value of the future benefit payments owed by the insurance company to the plans' participants.
- Fair values of real estate investments are valued using real estate valuation techniques and other methods that include reference to third-party sources and sales comparables where available.
- A portion of U.S. pension plan assets is held as a participating interest in an insurance annuity contract, which is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract. The participating interest is classified as Level 3 in the fair value hierarchy as the fair value is determined via a combination of quoted market prices, recently executed transactions, and an actuarial present value computation for contract obligations. At December 31, 2016, the participating interest in the annuity contract was valued at $121 million and consisted of $288 million in debt securities, less $167 million for the accumulated benefit obligation covered by the contract. At December 31, 2015, the participating interest in the annuity contract was valued at $125 million and consisted of $305 million in debt securities, less $180 million for the accumulated benefit obligation covered by the contract. The net change from 2015 to 2016 is due to a decrease in the fair value of the underlying investments of $17 million offset by a decrease in the present value of the contract obligation of $13 million. The participating interest is not available for meeting general pension benefit obligations in the near term. No future company contributions are required and no new benefits are being accrued under this insurance annuity contract.

The fair values of our pension plan assets at December 31, by asset class were as follows:

| | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | U.S. | | | | International | | | |
| | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
| **2016** | | | | | | | | |
| Equity Securities | | | | | | | | |
| U.S. | $ **632** | **-** | **14** | **646** | **628** | **-** | **-** | **628** |
| International | **342** | **-** | **-** | **342** | **428** | **-** | **-** | **428** |
| Common/collective trusts | **62** | **-** | **-** | **62** | **-** | **156** | **-** | **156** |
| Mutual funds | **-** | **-** | **-** | **-** | **268** | **139** | **-** | **407** |
| Debt Securities | | | | | | | | |
| Government | **-** | **38** | **-** | **38** | **470** | **-** | **-** | **470** |
| Corporate | **-** | **54** | **3** | **57** | **-** | **-** | **-** | **-** |
| Common/collective trusts | **-** | **-** | **-** | **-** | **-** | **385** | **-** | **385** |
| Mutual funds | **-** | **-** | **-** | **-** | **137** | **-** | **-** | **137** |
| Cash and cash equivalents | **-** | **-** | **-** | **-** | **48** | **-** | **-** | **48** |
| Derivatives | **-** | **-** | **-** | **-** | **18** | **-** | **-** | **18** |
| Real estate | **-** | **-** | **-** | **-** | **-** | **-** | **111** | **111** |
| Total in fair value hierarchy | $ **1,036** | **92** | **17** | **1,145** | **1,997** | **680** | **111** | **2,788** |
| | | | | | | | | |
| Investments measured at net asset value* | | | | | | | | |
| Equity Securities | | | | | | | | |
| Common/collective trusts | $ **-** | **-** | **-** | **410** | **-** | **-** | **-** | **-** |
| Debt Securities | | | | | | | | |
| Corporate | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **155** |
| Agency and mortgage-backed securities | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **27** |
| Common/collective trusts | **-** | **-** | **-** | **312** | **-** | **-** | **-** | **-** |
| Cash and cash equivalents | **-** | **-** | **-** | **36** | **-** | **-** | **-** | **11** |
| Real estate | **-** | **-** | **-** | **69** | **-** | **-** | **-** | **76** |
| Total** | $ **1,036** | **92** | **17** | **1,972** | **1,997** | **680** | **111** | **3,057** |

**In accordance with FASB ASC Topic 715, "Compensation—Retirement Benefits," certain investments that are to be measured at fair value using the net asset value per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Change in Fair Value of Plan Assets.*

***Excludes the participating interest in the insurance annuity contract with a net asset value of $121 million and net payables related to security transactions of $1 million.*

The fair values of our pension plan assets at December 31, by asset class were as follows:

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | U.S. | | | | | International | | | |
| | | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
| 2015 | | | | | | | | | |
| Equity Securities | | | | | | | | | |
| U.S. | $ | 777 | 3 | 2 | 782 | 609 | - | - | 609 |
| International | | 485 | - | - | 485 | 450 | - | - | 450 |
| Common/collective trusts | | - | - | - | - | - | 214 | - | 214 |
| Mutual funds | | - | - | - | - | 234 | 106 | - | 340 |
| Debt Securities | | | | | | | | | |
| Government | | 85 | 56 | - | 141 | 493 | - | - | 493 |
| Corporate | | - | 331 | 17 | 348 | - | - | - | - |
| Agency and mortgage-backed securities | | - | 80 | - | 80 | - | - | - | - |
| Common/collective trusts | | - | - | - | - | - | 406 | - | 406 |
| Mutual funds | | - | - | - | - | 136 | - | - | 136 |
| Cash and cash equivalents | | - | - | - | - | 46 | - | - | 46 |
| Derivatives | | - | (7) | - | (7) | (26) | - | - | (26) |
| Real estate | | - | - | - | - | - | - | 104 | 104 |
| Total in fair value hierarchy | $ | 1,347 | 463 | 19 | 1,829 | 1,942 | 726 | 104 | 2,772 |
| | | | | | | | | | |
| Investments measured at net asset value* | | | | | | | | | |
| Equity Securities | | | | | | | | | |
| Common/collective trusts | $ | - | - | - | 569 | - | - | - | - |
| Debt Securities | | | | | | | | | |
| Corporate | | - | - | - | - | - | - | - | 172 |
| Agency and mortgage-backed securities | | - | - | - | - | - | - | - | 36 |
| Cash and cash equivalents | | - | - | - | 60 | - | - | - | 10 |
| Real estate | | - | - | - | 63 | - | - | - | 65 |
| Total** | $ | 1,347 | 463 | 19 | 2,521 | 1,942 | 726 | 104 | 3,055 |

**In accordance with FASB ASC Topic 715, "Compensation—Retirement Benefits," certain investments that are to be measured at fair value using the net asset value per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Change in Fair Value of Plan Assets.*

***Excludes the participating interest in the insurance annuity contract with a net asset value of $125 million and net payables related to security transactions of $32 million.*

Level 3 activity was not material for all periods.

Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code of 1986, as amended. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2017, we expect to contribute approximately $320 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $110 million to our international qualified and nonqualified pension and postretirement benefit plans.

The following benefit payments, which are exclusive of amounts to be paid from the insurance annuity contract and which reflect expected future service, as appropriate, are expected to be paid:

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | Pension Benefits | | | Other Benefits |
| | | U.S. | Int'l. | |
| 2017 | $ | 352 | 116 | 42 |
| 2018 | | 290 | 131 | 39 |
| 2019 | | 287 | 124 | 36 |
| 2020 | | 277 | 129 | 34 |
| 2021 | | 292 | 137 | 30 |
| 2022–2026 | | 1,374 | 729 | 109 |

**Severance Accrual**
As a result of the current business environment's impact on our operating and capital plans, a reduction in our overall employee workforce occurred during 2015 and 2016. Severance accruals of $129 million were recorded in 2016. The following table summarizes our severance accrual activity for the year ended December 31, 2016:

| | Millions of Dollars | |
|---|---|---|
| Balance at December 31, 2015 | $ | 156 |
| Accruals | | **129** |
| Benefit payments | | **(206)** |
| Foreign currency translation adjustments | | **1** |
| Balance at December 31, 2016 | **$** | **80** |

Of the remaining balance at December 31, 2016, $52 million is classified as short-term.

**Defined Contribution Plans**
Most U.S. employees are eligible to participate in the ConocoPhillips Savings Plan (CPSP). Employees can deposit up to 75 percent of their eligible pay, subject to statutory limits, in the CPSP to a choice of approximately 34 investment funds. In 2016, employees who participate in the CPSP and contribute 1 percent of their eligible pay receive a 6 percent company cash match with a potential company discretionary cash contribution of up to 6 percent. Company contributions charged to expense for the CPSP and predecessor plans were $58 million in 2016, $109 million in 2015, and $116 million in 2014.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense recognized for these international plans was approximately $44 million in 2016, $55 million in 2015, and $66 million in 2014.

**Share-Based Compensation Plans**
The 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (the Plan) was approved by shareholders in May 2014. Over its 10-year life, the Plan allows the issuance of up to 79 million shares of our common stock for compensation to our employees and directors; however, as of the effective date of the Plan, (i) any shares of common stock available for future awards under the prior plans and (ii) any shares of common stock represented by awards granted under the prior plans that are forfeited, expire or are cancelled without delivery of shares of common stock or which result in the forfeiture of shares of common stock back to the company shall be available for awards under the Plan, and no new awards shall be granted under the prior plans. Of the 79 million shares available for issuance under the Plan, no more than 40 million shares of common stock are available for incentive stock options. The Human Resources and Compensation Committee

of our Board of Directors is authorized to determine the types, terms, conditions and limitations of awards granted. Awards may be granted in the form of, but not limited to, stock options, restricted stock units and performance share units to employees and nonemployee directors who contribute to the company's continued success and profitability.

Total share-based compensation expense is measured using the grant date fair value for our equity-classified awards and the settlement date fair value for our liability-classified awards. We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award); or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement, but not less than six months, as this is the minimum period of time required for an award to not be subject to forfeiture. Our share-based compensation programs generally provide accelerated vesting (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. Some of our share-based awards vest ratably (i.e., portions of the award vest at different times) while some of our awards cliff vest (i.e., all of the award vests at the same time). We recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

**Compensation Expense**—Total share-based compensation expense recognized in income (loss) and the associated tax benefit for the years ended December 31 were as follows:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| Compensation cost | $ **272** | 362 | 358 |
| Tax benefit | **92** | 123 | 125 |

**Stock Options**—Stock options granted under the provisions of the Plan and prior plans permit purchase of our common stock at exercise prices equivalent to the average market price of ConocoPhillips common stock on the date the options were granted. The options have terms of 10 years and generally vest ratably, with one-third of the options awarded vesting and becoming exercisable on each anniversary date following the date of grant. Options awarded to certain employees already eligible for retirement vest within six months of the grant date, but those options do not become exercisable until the end of the normal vesting period.

The fair market values of the options granted over the past three years were measured on the date of grant using the Black-Scholes-Merton option-pricing model. The weighted-average assumptions used were as follows:

| | **2016** | 2015 | 2014 |
|---|---|---|---|
| Assumptions used | | | |
| Risk-free interest rate | **1.55 %** | 1.79 | 1.86 |
| Dividend yield | **4.00 %** | 4.00 | 4.00 |
| Volatility factor | **26.80 %** | 23.32 | 25.31 |
| Expected life (years) | **6.37** | 5.79 | 6.12 |

There were no ranges in the assumptions used to determine the fair market values of our options granted over the past three years.

Due to the separation of our Downstream businesses in 2012, expected volatility for grants of options in 2014 was based on a three-year average historical stock price volatility of a group of peer companies. We believe our historical volatility for periods prior to the separation of our Downstream businesses is no longer relevant in estimating expected volatility. For 2015 and 2016, expected volatility was based on the weighted average blend of the company's historical stock price volatility from May 1, 2012 (the date of separation of our Downstream businesses) through the stock option grant date and the average historical stock price volatility of a group of peer companies for the expected term of the options.

The following summarizes our stock option activity for the year ended December 31, 2016:

| | Options | Weighted-Average Exercise Price | Weighted-Average Grant Date Fair Value | Millions of Dollars Aggregate Intrinsic Value |
|---|---|---|---|---|
| Outstanding at December 31, 2015 | 20,184,810 | $ 55.88 | | $ 42 |
| Granted | **4,434,400** | **33.13** | **$ 5.39** | |
| Exercised | **(62,536)** | **48.80** | | |
| Forfeited | **(272,646)** | **34.51** | | |
| Expired or cancelled | **(571,916)** | **45.46** | | |
| **Outstanding at December 31, 2016** | **23,712,112** | **$ 52.14** | | **$ 128** |
| **Vested at December 31, 2016** | **20,192,822** | **$ 52.85** | | **$ 93** |
| **Exercisable at December 31, 2016** | **15,932,144** | **$ 53.56** | | **$ 55** |

The weighted-average remaining contractual term of outstanding options, vested options and exercisable options at December 31, 2016, was 5.74 years, 5.25 years and 4.40 years, respectively. The weighted-average grant date fair value of stock option awards granted during 2015 and 2014 was $9.54 and $10.17, respectively. The aggregate intrinsic value of options exercised during 2015 and 2014 was $10 million and $89 million, respectively.

During 2016, we received $3 million in cash and realized a tax benefit of $4 million from the exercise of options. At December 31, 2016, the remaining unrecognized compensation expense from unvested options was $8 million, which will be recognized over a weighted-average period of 0.91 years, the longest period being 2.13 years.

**Stock Unit Program**—Generally, restricted stock units are granted annually under the provisions of the Plan. Restricted stock units granted prior to 2013 generally vest ratably in three equal annual installments beginning on the third anniversary of the grant date. Beginning in 2013, restricted stock units granted will vest in an aggregate installment on the third anniversary of the grant date. In addition, beginning in 2012, restricted stock units granted under the Plan for a variable long-term incentive program vest ratably in three equal annual installments beginning on the first anniversary of the grant date. Restricted stock units are also granted ad hoc to attract or retain key personnel, and the terms and conditions under which these restricted stock units vest vary by award. Upon vesting, the restricted stock units are settled by issuing one share of ConocoPhillips common stock per unit. Units awarded to retirement eligible employees vest six months from the grant date; however, those units are not issued as common stock until the earlier of separation from the company or the end of the regularly scheduled vesting period. Until issued as stock, most recipients of the restricted stock units receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. The grant date fair market value of these restricted stock units is deemed equal to the average ConocoPhillips stock price on the grant date. The grant date fair market value of units that do not receive a dividend equivalent while unvested is deemed equal to the average ConocoPhillips stock price on the grant date, less the net present value of the dividends that will not be received.

The following summarizes our stock unit activity for the year ended December 31, 2016:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2015 | 9,178,165 | $ 59.80 | |
| Granted | **4,613,469** | **32.15** | |
| Forfeited | **(169,018)** | **30.46** | |
| Issued | **(5,115,112)** | | **$ 191** |
| **Outstanding at December 31, 2016** | **8,507,504** | **$ 48.65** | |
| **Not Vested at December 31, 2016** | **5,990,350** | **$ 48.29** | |

At December 31, 2016, the remaining unrecognized compensation cost from the unvested units was $105 million, which will be recognized over a weighted-average period of 1.59 years, the longest period being 2.82 years. The weighted-average grant date fair value of stock unit awards granted during 2015 and 2014 was $65.40 and $62.72, respectively. The total fair value of stock units issued during 2015 and 2014 was $316 million and $256 million, respectively.

**Performance Share Program**—Under the Plan, we also annually grant restricted performance share units (PSUs) to senior management. These PSUs are authorized three years prior to their effective grant date (the performance period). Compensation expense is initially measured using the average fair market value of ConocoPhillips common stock and is subsequently adjusted, based on changes in the ConocoPhillips stock price through the end of each subsequent reporting period, through the grant date for stock-settled awards and the settlement date for cash-settled awards.

<u>*Stock-Settled*</u>

For performance periods beginning before 2009, PSUs do not vest until the employee becomes eligible for retirement by reaching age 55 with five years of service, and restrictions do not lapse until the employee separates from the company. With respect to awards for performance periods beginning in 2009 through 2012, PSUs do not vest until the earlier of the date the employee becomes eligible for retirement by reaching age 55 with five years of service or five years after the grant date of the award, and restrictions do not lapse until the earlier of the employee's separation from the company or five years after the grant date (although recipients can elect to defer the lapsing of restrictions until separation). We recognize compensation expense for these awards beginning on the grant date and ending on the date the PSUs are scheduled to vest. Since these awards are authorized three years prior to the grant date, for employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Until issued as stock, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. Beginning in 2013, PSUs authorized for future grants will vest, absent employee election to defer, upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending on the conclusion of the performance period. PSUs are settled by issuing one share of ConocoPhillips common stock per unit.

The following summarizes our stock-settled Performance Share Program activity for the year ended December 31, 2016:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2015 | 4,270,222 | $ 51.95 | |
| Granted | **48,065** | **33.13** | |
| Issued | **(428,763)** | | **$ 17** |
| **Outstanding at December 31, 2016** | **3,889,524** | **$ 51.93** | |
| **Not Vested at December 31, 2016** | **606,085** | **$ 53.34** | |

At December 31, 2016, the remaining unrecognized compensation cost from unvested stock-settled performance share awards was $3 million, which includes $1 million related to unvested stock-settled performance share awards tied to Phillips 66 stock held by ConocoPhillips employees, which will be recognized over a weighted-average period of 1.82 years, the longest period being 3.98 years. The weighted-average grant date fair value of stock-settled PSUs granted during 2015 and 2014 was $69.25 and $65.46, respectively. The total fair value of stock-settled PSUs issued during 2015 and 2014 was $25 million and $18 million, respectively.

*Cash-Settled*
In connection with and immediately following the separation of our Downstream businesses in 2012, grants of new PSUs, subject to a shortened performance period, were authorized. Once granted, these PSUs vest, absent employee election to defer, on the earlier of five years after the grant date of the award or the date the employee becomes eligible for retirement. For employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Otherwise, we recognize compensation expense beginning on the grant date and ending on the date the PSUs are scheduled to vest. These PSUs are settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and thus are classified as liabilities on the balance sheet. Until settlement occurs, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to compensation expense.

Beginning in 2013, PSUs authorized for future grants will vest upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending on the conclusion of the performance period. These PSUs will be settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and are classified as liabilities on the balance sheet. During the performance period, recipients of the PSUs do not receive a quarterly cash payment of a dividend equivalent, but after the performance period ends, until settlement in cash occurs, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to compensation expense.

The following summarizes our cash-settled Performance Share Program activity for the year ended December 31, 2016:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2015 | 1,459,236 | $ 46.54 | |
| Granted | **684,386** | **33.13** | |
| Settled | **(868,860)** | | **$ 31** |
| **Outstanding at December 31, 2016** | **1,274,762** | **$ 50.39** | |
| **Not Vested at December 31, 2016** | **584,789** | **$ 50.39** | |

At December 31, 2016, the remaining unrecognized compensation cost from unvested cash-settled performance share awards was $7 million, which will be recognized over a weighted-average period of 1.75 years, the longest period being 3.13 years. The weighted-average grant date fair value of cash-settled PSUs granted during 2015 and 2014 was $46.54 and $69.23, respectively. The total fair value of cash-settled performance share awards settled during 2015 and 2014 was $6 million and zero, respectively.

From inception of the Performance Share Program through 2013, approved PSU awards were granted after the conclusion of performance periods. Beginning in February 2014, initial target PSU awards are issued near the beginning of new performance periods. These initial target PSU awards will terminate at the end of the performance periods and will be settled after the performance periods have ended. Also in 2014, initial target PSU awards were issued for open performance periods that began in prior years. For the open performance period beginning in 2012, the initial target PSU awards will terminate at the end of the three-year performance period and will be replaced with approved PSU awards. For the open performance period beginning in 2013, the initial target PSU awards will terminate at the end of the three-year performance period and will be settled after the performance period has ended. There is no effect on recognition of compensation expense.

**Other**—In addition to the above active programs, we have outstanding shares of restricted stock and restricted stock units that were either issued to replace awards held by employees of companies we acquired or issued as part of a compensation program that has been discontinued. Generally, the recipients of the restricted shares or units receive a quarterly dividend or dividend equivalent.

The following summarizes the aggregate activity of these restricted shares and units for the year ended December 31, 2016:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2015 | 1,272,136 | $ 33.25 | |
| Granted | **99,300** | **40.36** | |
| Cancelled | **(15,964)** | **20.69** | |
| Issued | **(37,508)** | | **$ 2** |
| **Outstanding at December 31, 2016** | **1,317,964** | **$ 33.16** | |
| **Not Vested at December 31, 2016** | **-** | | |

At December 31, 2016, all outstanding restricted stock and restricted stock units were fully vested and there was no remaining compensation cost to be recorded. The weighted-average grant date fair value of awards granted during 2015 and 2014 was $58.66 and $71.23, respectively. The total fair value of awards issued during 2015 and 2014 was $3 million and $3 million, respectively.

## Note 19—Income Taxes

Income taxes charged to income (loss) from continuing operations were:

| | | Millions of Dollars | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| **Income Taxes** | | | |
| Federal | | | |
| Current | $ **(9)** | (718) | 188 |
| Deferred | **(1,634)** | (1,443) | 365 |
| Foreign | | | |
| Current | **393** | 745 | 2,846 |
| Deferred | **(519)** | (1,315) | 252 |
| State and local | | | |
| Current | **(135)** | 8 | 46 |
| Deferred | **(67)** | (145) | (114) |
| | $ **(1,971)** | (2,868) | 3,583 |

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Major components of deferred tax liabilities and assets at December 31 were:

| | Millions of Dollars | |
|---|---|---|
| | **2016** | 2015 |
| **Deferred Tax Liabilities** | | |
| PP&E and intangibles | $ **15,099** | 16,378 |
| Investment in joint ventures | **933** | 866 |
| Inventory | **36** | 25 |
| Deferred state income tax | **203** | 128 |
| Partnership income deferral | **-** | 44 |
| Other | **486** | 453 |
| Total deferred tax liabilities | **16,757** | 17,894 |
| **Deferred Tax Assets** | | |
| Benefit plan accruals | **1,280** | 1,160 |
| Asset retirement obligations and accrued environmental costs | **3,514** | 4,426 |
| Other financial accruals and deferrals | **317** | 616 |
| Loss and credit carryforwards | **3,522** | 1,579 |
| Other | **250** | 134 |
| Total deferred tax assets | **8,883** | 7,915 |
| Less: valuation allowance | **(675)** | (734) |
| Net deferred tax assets | **8,208** | 7,181 |
| Net deferred tax liabilities | $ **8,549** | 10,713 |

At December 31, 2016, noncurrent assets and liabilities include deferred taxes of $400 million and $8,949 million, respectively. At December 31, 2015, noncurrent assets and liabilities include deferred taxes of $286 million and $10,999 million, respectively.

At December 31, 2016, the components of our loss and credit carryforwards before and after consideration of the applicable valuation allowances are:

| | Millions of Dollars | | |
|---|---|---|---|
| | Gross Deferred Tax Asset | Net Deferred Tax Asset After Valuation Allowance | Expiration of Net Deferred Tax Asset |
| U.S. federal net operating loss | $ 1,648 | $ 1,648 | 2036 |
| U.S. foreign tax credits | 480 | 296 | 2025-2026 |
| U.S. general business credits | 96 | 96 | 2031 |
| State net operating losses and tax credits | 502 | 49 | Post 2024 |
| Foreign net operating losses and tax credits | 796 | 783 | Post 2025 |
| | $ 3,522 | $ 2,872 | |

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2016, valuation allowances decreased a total of $59 million. This decrease primarily relates to the expected realization of certain deferred tax assets. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects remaining net deferred tax assets will primarily be realized as offsets to reversing deferred tax liabilities.

At December 31, 2016, unremitted income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $3,720 million. Deferred income taxes have not been provided on this amount, as we do not plan to initiate any action that would require the payment of income taxes. Due to the nature of our structures within the jurisdictions in which we operate, as well as the complex nature of the relevant tax laws, it is not practicable to estimate the amount of additional tax, if any, that might be payable on this income if distributed.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2016, 2015 and 2014:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| Balance at January 1 | **$ 459** | 442 | 655 |
| Additions based on tax positions related to the current year | **32** | 54 | 46 |
| Additions for tax positions of prior years | **19** | 4 | 7 |
| Reductions for tax positions of prior years | **(118)** | (37) | (228) |
| Settlements | **(9)** | (4) | (28) |
| Lapse of statute | **(2)** | - | (10) |
| Balance at December 31 | **$ 381** | 459 | 442 |

Included in the balance of unrecognized tax benefits for 2016, 2015 and 2014 were $359 million, $354 million and $348 million, respectively, which, if recognized, would impact our effective tax rate.

At December 31, 2016, 2015 and 2014, accrued liabilities for interest and penalties totaled $54 million, $79 million and $65 million, respectively, net of accrued income taxes. Interest and penalties resulted in a benefit to earnings of $18 million in 2016, a reduction to earnings of $11 million in 2015, and a benefit to earnings of $43 million in 2014.

We and our subsidiaries file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions are generally complete as follows: United Kingdom (2014), Canada (2009), United States (2010) and Norway (2015). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world. As a consequence, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

The amounts of U.S. and foreign income (loss) from continuing operations before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes, were:

| | | Millions of Dollars | | | Percent of Pre-Tax Income (Loss) | | |
|---|---|---|---|---|---|---|---|
| | | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| Income (loss) before income taxes from continuing operations | | | | | | | |
| United States | $ | **(4,410)** | (4,150) | 2,310 | **79.7 %** | 57.3 | 24.6 |
| Foreign | | **(1,120)** | (3,089) | 7,080 | **20.3** | 42.7 | 75.4 |
| | $ | **(5,530)** | (7,239) | 9,390 | **100.0 %** | 100.0 | 100.0 |
| Federal statutory income tax | $ | **(1,936)** | (2,534) | 3,287 | **35.0 %** | 35.0 | 35.0 |
| Non-U.S. effective tax rates | | **365** | 381 | 376 | **(6.6)** | (5.3) | 4.0 |
| Foreign tax law change | | **(161)** | (426) | - | **2.9** | 5.9 | - |
| U.S. fair value election | | **-** | (185) | - | **-** | 2.6 | - |
| Enhanced Oil Recovery Credit | | **(62)** | - | - | **1.1** | - | - |
| State income tax | | **(131)** | (89) | (44) | **2.4** | 1.2 | (0.5) |
| Other | | **(46)** | (15) | (36) | **0.8** | 0.2 | (0.4) |
| | $ | **(1,971)** | (2,868) | 3,583 | **35.6 %** | 39.6 | 38.1 |

The decrease in the effective tax rate for 2016 was primarily due to higher income in high tax jurisdictions, lower losses in low tax jurisdictions, and reduced net tax benefit from tax law changes.

The increase in the effective tax rate for 2015 was primarily due to the U.K. tax law change and electing the fair market value method of apportioning interest expense for prior years, discussed below; partially offset by lower income in high tax jurisdictions and the Canadian tax law change, discussed below.

In the United Kingdom, legislation was enacted on September 15, 2016, to decrease the overall U.K. upstream corporation tax rate from 50 percent to 40 percent effective January 1, 2016. As a result, a $161 million net tax benefit for revaluing the U.K. deferred tax liability is reflected in the “Income tax provision (benefit)” line on our consolidated income statement.

In the United Kingdom, legislation was enacted on March 26, 2015, to decrease the overall U.K. upstream corporation tax rate from 62 percent to 50 percent effective January 1, 2015. As a result, a $555 million net tax benefit for revaluing the U.K. deferred tax liability is reflected in the “Income tax provision (benefit)” line on our consolidated income statement.

In Canada, legislation was enacted on June 29, 2015, to increase the overall Canadian corporation tax rate from 25 percent to 27 percent effective July 1, 2015. As a result, a $129 million net tax expense for revaluing the Canadian deferred tax liability is reflected in the “Income tax provision (benefit)” line on our consolidated income statement.

In December 2015, we filed refund claims for prior years electing the fair market value method of apportioning interest in the United States. As a result, a $185 million tax benefit was recorded in the fourth quarter of 2015.

Certain operating losses in jurisdictions outside of the U.S. only yield a tax benefit in the U.S. as a worthless security deduction. For 2016, 2015 and 2014 the amount of the benefit was $60 million, $491 million and $122 million, respectively.

**Note 20—Accumulated Other Comprehensive Income**

Accumulated other comprehensive income (loss) in the equity section of the balance sheet included:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | Defined Benefit Plans | Foreign Currency Translation | Accumulated Other Comprehensive Income (Loss) |
| December 31, 2013 | $ | (824) | 2,826 | 2,002 |
| Other comprehensive loss | | (437) | (3,467) | (3,904) |
| December 31, 2014 | | (1,261) | (641) | (1,902) |
| Other comprehensive income (loss) | | 818 | (5,163) | (4,345) |
| December 31, 2015 | | (443) | (5,804) | (6,247) |
| Other comprehensive income (loss) | | **(104)** | **158** | **54** |
| **December 31, 2016** | **$** | **(547)** | **(5,646)** | **(6,193)** |

There were no items within accumulated other comprehensive income (loss) related to noncontrolling interests.

The following table summarizes reclassifications out of accumulated other comprehensive loss during the years ended December 31:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2016** | 2015 |
| Defined Benefit Plans | **$** | **179** | 251 |
| *Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:* | *$* | ***95*** | *133* |

*See Note 18—Employee Benefit Plans, for additional information.*

## Note 21—Cash Flow Information

Amounts included in continuing operations for the years ended December 31 were:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2016** | 2015 | 2014 |
| **Noncash Investing and Financing Activities** | | | |
| Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations* | **$ (1,017)** | 402 | 1,611 |
| **Cash Payments (Receipts)** | | | |
| Interest | **$ 1,151** | 920 | 669 |
| Income taxes** | **(318)** | 523 | 4,203 |
| **Net Sales (Purchases) of Short-Term Investments** | | | |
| Short-term investments purchased | **$ (1,753)** | - | (876) |
| Short-term investments sold | **1,702** | - | 1,129 |
| | **$ (51)** | - | 253 |

**Includes $68 million in 2014, primarily related to the impact of U.K. tax law changes on the deductibility of decommissioning costs.*
***Net of $585 million and $642 million in 2016 and 2015, respectively, related to refunds received from the Internal Revenue Service.*

## Note 22—Other Financial Information

Amounts included in continuing operations for the years ended December 31 were:

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | | **2016** | 2015 | 2014 |
| **Interest and Debt Expense** | | | | |
| Incurred | | | | |
| Debt | $ | **1,279** | 1,130 | 1,063 |
| Other | | **123** | 84 | 73 |
| | | **1,402** | 1,214 | 1,136 |
| Capitalized | | **(157)** | (294) | (488) |
| Expensed | $ | **1,245** | 920 | 648 |
| **Other Income** | | | | |
| Interest income | $ | **57** | 45 | 83 |
| Other, net | | **198** | 80 | 283 |
| | $ | **255** | 125 | 366 |
| **Research and Development Expenditures**—expensed | $ | **116** | 222 | 263 |
| **Shipping and Handling Costs*** | $ | **1,139** | 1,181 | 1,360 |

**Amounts included in production and operating expenses.*

| | | | | |
|---|---|---|---|---|
| **Foreign Currency Transaction (Gains) Losses**—after-tax | | | | |
| Alaska | $ | **-** | - | - |
| Lower 48 | | **-** | - | - |
| Canada | | **1** | - | (4) |
| Europe and North Africa | | **(7)** | (22) | (56) |
| Asia Pacific and Middle East | | **(9)** | (78) | - |
| Other International | | **7** | (9) | - |
| Corporate and Other | | **(18)** | 45 | 16 |
| | $ | **(26)** | (64) | (44) |

| | Millions of Dollars | |
|---|---|---|
| | **2016** | 2015 |
| **Properties, Plants and Equipment** | | |
| Proved properties | **$ 119,970** | 122,796 |
| Unproved properties | **5,150** | 7,410 |
| Other | **6,286** | 6,653 |
| Gross properties, plants and equipment | **131,406** | 136,859 |
| Less: Accumulated depreciation, depletion and amortization | **(73,075)** | (70,413) |
| Net properties, plants and equipment | **$ 58,331** | 66,446 |

**Note 23—Related Party Transactions**

Our related parties primarily include equity method investments and certain trusts for the benefit of employees.

Significant transactions with our equity affiliates were:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2016** | 2015 | 2014 |
| Operating revenues and other income | $ | **133** | 118 | 119 |
| Purchases | | **101** | 97 | 190 |
| Operating expenses and selling, general and administrative expenses | | **63** | 62 | 70 |
| Net interest (income) expense* | | **(12)** | (9) | (44) |

**We paid interest to, or received interest from, various affiliates. See Note 7—Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.*

The table above includes transactions with Freeport LNG through the date of the termination agreement and excludes the termination fee. See Note 7—Investments, Loans and Long-Term Receivables, for additional information.

**Note 24—Segment Disclosures and Related Information**

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International.

After agreeing to sell our Nigeria business in 2012, we completed the sale in 2014. Results for these operations have been reported as discontinued operations in the applicable periods presented. For additional information, see Note 3—Discontinued Operations.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, corporate overhead and certain technology activities, including licensing revenues. Corporate assets include all cash and cash equivalents.

We evaluate performance and allocate resources based on net income (loss) attributable to ConocoPhillips. Segment accounting policies are the same as those in Note 1—Accounting Policies. Intersegment sales are at prices that approximate market.

**Analysis of Results by Operating Segment**

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2016** | 2015 | 2014 |
| **Sales and Other Operating Revenues** | | | | |
| Alaska | **$** | **3,681** | 4,351 | 8,382 |
| Lower 48 | | **10,719** | 11,976 | 21,721 |
| Intersegment eliminations | | **(17)** | (63) | (107) |
| Lower 48 | | **10,702** | 11,913 | 21,614 |
| Canada | | **2,192** | 2,454 | 5,162 |
| Intersegment eliminations | | **(218)** | (318) | (753) |
| Canada | | **1,974** | 2,136 | 4,409 |
| Europe and North Africa | | **3,462** | 6,110 | 10,665 |
| Intersegment eliminations | | **-** | (4) | (49) |
| Europe and North Africa | | **3,462** | 6,106 | 10,616 |
| Asia Pacific and Middle East | | **3,705** | 4,746 | 7,425 |
| Intersegment eliminations | | **-** | (1) | (1) |
| Asia Pacific and Middle East | | **3,705** | 4,745 | 7,424 |
| Other International | | **-** | 1 | - |
| Corporate and Other | | **169** | 312 | 79 |
| Consolidated sales and other operating revenues | **$** | **23,693** | 29,564 | 52,524 |
| | | | | |
| **Depreciation, Depletion, Amortization and Impairments** | | | | |
| Alaska | **$** | **868** | 690 | 584 |
| Lower 48 | | **4,358** | 4,227 | 3,911 |
| Canada | | **975** | 788 | 962 |
| Europe and North Africa | | **1,253** | 2,565 | 2,345 |
| Asia Pacific and Middle East | | **1,606** | 2,981 | 1,275 |
| Other International | | **1** | - | 1 |
| Corporate and Other | | **140** | 107 | 107 |
| Consolidated depreciation, depletion, amortization and impairments | **$** | **9,201** | 11,358 | 9,185 |

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2016** | 2015 | 2014 |
| **Equity in Earnings of Affiliates** | | | | |
| Alaska | $ | **9** | 4 | 9 |
| Lower 48 | | **(6)** | (5) | 1 |
| Canada | | **89** | 78 | 1,385 |
| Europe and North Africa | | **22** | 23 | 37 |
| Asia Pacific and Middle East | | **(51)** | 550 | 1,089 |
| Other International | | **-** | 8 | 9 |
| Corporate and Other | | **(11)** | (3) | (1) |
| Consolidated equity in earnings of affiliates | $ | **52** | 655 | 2,529 |
| | | | | |
| **Income Taxes** | | | | |
| Alaska | $ | **(59)** | (71) | 1,081 |
| Lower 48 | | **(1,328)** | (1,119) | (92) |
| Canada | | **(383)** | (223) | 236 |
| Europe and North Africa | | **(46)** | (854) | 1,590 |
| Asia Pacific and Middle East | | **306** | 467 | 1,194 |
| Other International | | **(40)** | (456) | (102) |
| Corporate and Other | | **(421)** | (612) | (324) |
| Consolidated income taxes | $ | **(1,971)** | (2,868) | 3,583 |
| | | | | |
| **Net Income (Loss) Attributable to ConocoPhillips** | | | | |
| Alaska | $ | **319** | 4 | 2,041 |
| Lower 48 | | **(2,257)** | (1,932) | (22) |
| Canada | | **(935)** | (1,044) | 940 |
| Europe and North Africa | | **394** | 409 | 814 |
| Asia Pacific and Middle East | | **209** | (463) | 2,939 |
| Other International | | **(16)** | (593) | (100) |
| Corporate and Other | | **(1,329)** | (809) | (874) |
| Discontinued operations | | **-** | - | 1,131 |
| Consolidated net income (loss) attributable to ConocoPhillips | $ | **(3,615)** | (4,428) | 6,869 |
| | | | | |
| **Investments In and Advances To Affiliates** | | | | |
| Alaska | $ | **58** | 61 | 53 |
| Lower 48 | | **426** | 455 | 471 |
| Canada | | **8,784** | 8,165 | 9,484 |
| Europe and North Africa | | **62** | 70 | 126 |
| Asia Pacific and Middle East | | **11,611** | 11,780 | 14,022 |
| Other International | | **-** | - | 59 |
| Corporate and Other | | **4** | 15 | 15 |
| Consolidated investments in and advances to affiliates | $ | **20,945** | 20,546 | 24,230 |

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2016** | 2015 | 2014 |
| **Total Assets** | | | | |
| Alaska | $ | **12,314** | 12,555 | 12,655 |
| Lower 48 | | **22,673** | 26,932 | 30,185 |
| Canada | | **17,548** | 17,221 | 21,764 |
| Europe and North Africa | | **11,727** | 13,703 | 16,970 |
| Asia Pacific and Middle East | | **20,451** | 22,318 | 25,976 |
| Other International | | **97** | 282 | 1,116 |
| Corporate and Other | | **4,962** | 4,473 | 7,815 |
| Discontinued operations | | **-** | - | 58 |
| Consolidated total assets | $ | **89,772** | 97,484 | 116,539 |
| | | | | |
| **Capital Expenditures and Investments** | | | | |
| Alaska | $ | **883** | 1,352 | 1,564 |
| Lower 48 | | **1,262** | 3,765 | 6,054 |
| Canada | | **698** | 1,255 | 2,340 |
| Europe and North Africa | | **1,020** | 1,573 | 2,540 |
| Asia Pacific and Middle East | | **838** | 1,812 | 3,877 |
| Other International | | **104** | 173 | 520 |
| Corporate and Other | | **64** | 120 | 190 |
| Consolidated capital expenditures and investments | $ | **4,869** | 10,050 | 17,085 |
| | | | | |
| **Interest Income and Expense** | | | | |
| Interest income | | | | |
| Corporate | $ | **47** | 36 | 40 |
| Lower 48 | | **-** | - | 35 |
| Europe and North Africa | | **2** | 2 | 2 |
| Asia Pacific and Middle East | | **8** | 6 | 6 |
| Other International | | **-** | 1 | - |
| Interest and debt expense | | | | |
| Corporate | $ | **1,245** | 920 | 648 |
| | | | | |
| **Sales and Other Operating Revenues by Product** | | | | |
| Crude oil | $ | **10,801** | 12,830 | 23,784 |
| Natural gas | | **9,401** | 11,888 | 20,717 |
| Natural gas liquids | | **837** | 952 | 2,245 |
| Other* | | **2,654** | 3,894 | 5,778 |
| Consolidated sales and other operating revenues by product | $ | **23,693** | 29,564 | 52,524 |

**Includes LNG and bitumen.*

**Geographic Information**

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Sales and Other Operating Revenues[1] | | | Long-Lived Assets[2] | | |
| | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| United States | $ **14,400** | 16,284 | 30,019 | **32,949** | 37,445 | 39,641 |
| Australia[3] | **1,353** | 2,127 | 3,258 | **12,259** | 12,788 | 14,969 |
| Canada | **1,974** | 2,136 | 4,409 | **16,846** | 16,766 | 20,874 |
| China | **551** | 782 | 1,701 | **1,372** | 1,647 | 1,913 |
| Indonesia | **938** | 1,165 | 1,963 | **856** | 1,191 | 1,526 |
| Malaysia | **735** | 598 | 403 | **3,323** | 3,599 | 3,811 |
| Norway | **1,645** | 2,107 | 3,794 | **6,228** | 6,933 | 8,142 |
| United Kingdom | **1,816** | 4,005 | 6,594 | **3,209** | 4,154 | 5,327 |
| Other foreign countries | **281** | 360 | 383 | **2,234** | 2,469 | 3,471 |
| Worldwide consolidated | $ **23,693** | 29,564 | 52,524 | **79,276** | 86,992 | 99,674 |

*(1)Sales and other operating revenues are attributable to countries based on the location of the selling operation.*
*(2)Defined as net PP&E plus investments in and advances to affiliated companies.*
*(3)Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.*

**Note 25—New Accounting Standards**

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers" (ASU No. 2014-09), which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers. This ASU supersedes the revenue recognition requirements in FASB ASC Topic 605, "Revenue Recognition," and most industry-specific guidance. This ASU sets forth a five-step model for determining when and how revenue is recognized. Under the model, an entity will be required to recognize revenue to depict the transfer of goods or services to a customer at an amount reflecting the consideration it expects to receive in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts.

In August 2015, the FASB issued ASU No. 2015-14, "Deferral of the Effective Date," which defers the effective date of ASU No. 2014-09. The ASU is now effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for interim and annual periods beginning after December 15, 2016. Entities may choose to adopt the standard using either a full retrospective approach or a modified retrospective approach.

ASU No. 2014-09 was amended in March 2016 by the provisions of ASU No. 2016-08, "Principal versus Agent Considerations (Reporting Revenue Gross versus Net)," in April 2016 by the provisions of ASU No. 2016-10, "Identifying Performance Obligations and Licensing," in May 2016 by the provisions of ASU No. 2016-12, "Narrow-Scope Improvements and Practical Expedients," and in December 2016 by the provisions of ASU No. 2016-20, "Technical Corrections and Improvements to Topic 606, Revenue From Contracts With Customers."

We will adopt the provisions of ASU No. 2014-09, as amended, with effect from January 1, 2018, and have elected not to early adopt the standard. We intend to adopt the new standard using the modified retrospective approach which we will apply only to contracts within the scope of the standard that are not complete at the date of initial application. Under this approach, we will apply the guidance retrospectively only to the most current period presented in the financial statements. Overall, the impact to our financial statements is expected to be immaterial.

In February 2016, the FASB issued ASU No. 2016-02, "Leases" (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB ASC Topic 840, "Leases," and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements. While we continue to evaluate the ASU, we expect the adoption of the ASU to have a material impact on our consolidated financial statements and disclosures.

In June 2016, the FASB issued ASU No. 2016-13, "Measurement of Credit Losses on Financial Instruments" (ASU No. 2016-13), which sets forth the current expected credit loss model, a new forward-looking impairment model for certain financial instruments based on expected losses rather than incurred losses. The ASU is effective for interim and annual periods beginning after December 15, 2019, and early adoption of the standard is permitted. Entities are required to adopt ASU No. 2016-13 using a modified retrospective approach, subject to certain limited exceptions. We are currently evaluating the impact of the adoption of this ASU.

**Oil and Gas Operations** (Unaudited)

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, "Extractive Activities—Oil and Gas," and regulations of the U.S. Securities and Exchange Commission (SEC), we are making certain supplemental disclosures about our oil and gas exploration and production operations.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates' oil and gas activities in our operating segments. As a result, amounts reported as equity affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report.

As required by current authoritative guidelines, the estimated future date when an asset will be permanently shut down for economic reasons is based on historical 12-month first-of-month average prices and current costs. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Generally, our proved reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to production sharing contracts (PSCs), which are reported under the "economic interest" method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices, recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. At December 31, 2016, approximately 7 percent of our total proved reserves were under PSCs, located in our Asia Pacific/Middle East geographic reporting area, and 23 percent of our total proved reserves were under a variable-royalty regime, located in our Canada geographic reporting area.

Our reserves disclosures by geographic area include the United States, Canada, Europe (Norway and the United Kingdom), Asia Pacific/Middle East, Africa and Other Areas. Other Areas primarily consists of Russia, which we exited in 2015.

As part of our asset disposition program, we sold our interest in the Nigeria business in July 2014. This business was considered held for sale since the fourth quarter of 2012 and has been reported as discontinued operations for the applicable periods presented. Accordingly, the Results of Operations, Average Sales Prices and Net Production tables included within the supplemental oil and gas disclosures reflect the associated earnings and production as discontinued operations. See Note 3—Discontinued Operations, for additional information.

**Reserves Governance**

The recording and reporting of proved reserves are governed by criteria established by regulations of the SEC and FASB. Proved reserves are 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain it will commence the project within a reasonable time.

Proved reserves are further classified as either developed or undeveloped. Proved developed reserves are proved reserves that 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, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved reserves expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

We have a companywide, comprehensive, SEC-compliant internal policy that governs the determination and reporting of proved reserves. This policy is applied by the geologists and reservoir engineers in our business units around the world. As part of our internal control process, each business unit's reserves processes and controls are reviewed annually by an internal team which is headed by the company's Manager of Reserves Compliance and Reporting. This team, composed of internal reservoir engineers, geologists, finance personnel and a senior representative from DeGolyer and MacNaughton (D&M), a third-party petroleum engineering consulting firm, reviews the business units' reserves for adherence to SEC guidelines and company policy through on-site visits, teleconferences and review of documentation. In addition to providing independent reviews, this internal team also ensures reserves are calculated using consistent and appropriate standards and procedures. This team is independent of business unit line management and is responsible for reporting its findings to senior management. The team is responsible for communicating our reserves policy and procedures and is available for internal peer reviews and consultation on major projects or technical issues throughout the year. All of our proved reserves held by consolidated companies and our share of equity affiliates have been estimated by ConocoPhillips.

During 2016, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2016, were reviewed by D&M. The purpose of their review was to assess whether the adequacy and effectiveness of our internal processes and controls used to determine estimates of proved reserves are in accordance with SEC regulations. In such review, ConocoPhillips' technical staff presented D&M with an overview of the reserves data, as well as the methods and assumptions used in estimating reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures and relevant economic criteria. Management's intent in retaining D&M to review its processes and controls was to provide objective third-party input on these processes and controls. D&M's opinion was the general processes and controls employed by ConocoPhillips in estimating its December 31, 2016, proved reserves for the properties reviewed are in accordance with the SEC reserves definitions. D&M's report is included as Exhibit 99 of this Annual Report on Form 10-K.

The technical person primarily responsible for overseeing the processes and internal controls used in the preparation of the company's reserves estimates is the Manager of Reserves Compliance and Reporting. This individual holds a master's degree in petroleum engineering. He is a member of the Society of Petroleum Engineers with over 25 years of oil and gas industry experience and has held positions of increasing responsibility in reservoir engineering, subsurface and asset management in the United States and several international field locations.

Engineering estimates of the quantities of proved reserves are inherently imprecise. See the "Critical Accounting Estimates" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional discussion of the sensitivities surrounding these estimates.

**Proved Reserves**

| Years Ended December 31 | Crude Oil Millions of Barrels | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed and Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2013 | 1,106 | 606 | 1,712 | 22 | 456 | 232 | 237 | - | 2,659 |
| Revisions | (6) | 25 | 19 | 3 | (1) | 5 | - | - | 26 |
| Improved recovery | 8 | - | 8 | 2 | - | 3 | - | - | 13 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 16 | 116 | 132 | 2 | - | 16 | - | - | 150 |
| Production | (61) | (71) | (132) | (5) | (44) | (29) | (5) | - | (215) |
| Sales | - | - | - | - | - | - | (28) | - | (28) |
| End of 2014 | 1,063 | 676 | 1,739 | 24 | 411 | 227 | 204 | - | 2,605 |
| Revisions | (115) | (69) | (184) | - | (21) | (29) | - | - | (234) |
| Improved recovery | 4 | 4 | 8 | 1 | - | 31 | - | - | 40 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 20 | 57 | 77 | 1 | - | 7 | - | - | 85 |
| Production | (57) | (78) | (135) | (4) | (44) | (33) | - | - | (216) |
| Sales | - | (2) | (2) | (8) | - | - | - | - | (10) |
| End of 2015 | 915 | 588 | 1,503 | 14 | 346 | 203 | 204 | - | 2,270 |
| Revisions | (57) | (93) | (150) | 3 | - | 6 | - | - | (141) |
| Improved recovery | 6 | 3 | 9 | - | - | 7 | - | - | 16 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 33 | 79 | 112 | - | - | 7 | - | - | 119 |
| Production | (60) | (71) | (131) | (3) | (43) | (35) | (1) | - | (213) |
| Sales | - | - | - | (1) | - | (3) | - | - | (4) |
| **End of 2016** | 837 | 506 | 1,343 | 13 | 303 | 185 | 203 | - | 2,047 |
| *Equity affiliates* | | | | | | | | | |
| End of 2013 | - | - | - | - | - | 86 | - | 4 | 90 |
| Revisions | - | - | - | - | - | 17 | - | 3 | 20 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (5) | - | (2) | (7) |
| Sales | - | - | - | - | - | - | - | - | - |
| End of 2014 | - | - | - | - | - | 98 | - | 5 | 103 |
| Revisions | - | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (5) | - | (1) | (6) |
| Sales | - | - | - | - | - | - | - | (4) | (4) |
| End of 2015 | - | - | - | - | - | 93 | - | - | 93 |
| Revisions | - | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (5) | - | - | (5) |
| Sales | - | - | - | - | - | - | - | - | - |
| **End of 2016** | - | - | - | - | - | 88 | - | - | 88 |
| *Total company* | | | | | | | | | |
| End of 2013 | 1,106 | 606 | 1,712 | 22 | 456 | 318 | 237 | 4 | 2,749 |
| End of 2014 | 1,063 | 676 | 1,739 | 24 | 411 | 325 | 204 | 5 | 2,708 |
| End of 2015 | 915 | 588 | 1,503 | 14 | 346 | 296 | 204 | - | 2,363 |
| **End of 2016** | 837 | 506 | 1,343 | 13 | 303 | 273 | 203 | - | 2,135 |

| Years Ended December 31 | Crude Oil Millions of Barrels | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2013 | 1,003 | 268 | 1,271 | 22 | 247 | 126 | 230 | - | 1,896 |
| End of 2014 | 950 | 313 | 1,263 | 23 | 237 | 142 | 199 | - | 1,864 |
| End of 2015 | 819 | 283 | 1,102 | 13 | 200 | 139 | 204 | - | 1,658 |
| **End of 2016** | 747 | 256 | 1,003 | 13 | 184 | 106 | 203 | - | 1,509 |
| *Equity affiliates* | | | | | | | | | |
| End of 2013 | - | - | - | - | - | 86 | - | 4 | 90 |
| End of 2014 | - | - | - | - | - | 98 | - | 5 | 103 |
| End of 2015 | - | - | - | - | - | 93 | - | - | 93 |
| **End of 2016** | - | - | - | - | - | 88 | - | - | 88 |
| **Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2013 | 103 | 338 | 441 | - | 209 | 106 | 7 | - | 763 |
| End of 2014 | 113 | 363 | 476 | 1 | 174 | 85 | 5 | - | 741 |
| End of 2015 | 96 | 305 | 401 | 1 | 146 | 64 | - | - | 612 |
| **End of 2016** | 90 | 250 | 340 | - | 119 | 79 | - | - | 538 |
| *Equity affiliates* | | | | | | | | | |
| End of 2013 | - | - | - | - | - | - | - | - | - |
| End of 2014 | - | - | - | - | - | - | - | - | - |
| End of 2015 | - | - | - | - | - | - | - | - | - |
| **End of 2016** | - | - | - | - | - | - | - | - | - |

Notable changes in proved crude oil reserves in the three years ended December 31, 2016, included:

- Revisions: In 2016, revisions in Lower 48 and Alaska were primarily due to lower prices. In 2015, revisions in Alaska, Lower 48 and Asia Pacific/Middle East were primarily due to lower prices.

- Extensions and discoveries: In 2016, extensions and discoveries in Alaska were primarily due to drilling success in the Western North Slope. In 2016 and 2014, extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford and Bakken.

- Sales: In 2014, sales in Africa reflect the sale of the Nigeria business.

| Years Ended December 31 | Natural Gas Liquids | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
| **Developed and Undeveloped** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| End of 2013 | 125 | 462 | 587 | 56 | 28 | 14 | 14 | 699 |
| Revisions | - | (13) | (13) | 15 | (1) | 2 | - | 3 |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | 26 | 26 | 3 | - | - | - | 29 |
| Production | (5) | (35) | (40) | (8) | (3) | (3) | (1) | (55) |
| Sales | - | - | - | (1) | - | - | (13) | (14) |
| End of 2014 | 120 | 440 | 560 | 65 | 24 | 13 | - | 662 |
| Revisions | (1) | (84) | (85) | (10) | (1) | (2) | - | (98) |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | 10 | 10 | 2 | - | - | - | 12 |
| Production | (5) | (36) | (41) | (9) | (3) | (3) | - | (56) |
| Sales | - | (9) | (9) | (3) | - | - | - | (12) |
| End of 2015 | 114 | 321 | 435 | 45 | 20 | 8 | - | 508 |
| Revisions | (3) | (29) | (32) | 9 | 2 | - | - | (21) |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | 18 | 18 | 2 | - | - | - | 20 |
| Production | (4) | (32) | (36) | (8) | (3) | (3) | - | (50) |
| Sales | - | - | - | - | - | - | - | - |
| **End of 2016** | 107 | 278 | 385 | 48 | 19 | 5 | - | 457 |
| *Equity affiliates* | | | | | | | | |
| End of 2013 | - | - | - | - | - | 45 | - | 45 |
| Revisions | - | - | - | - | - | 10 | - | 10 |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (2) | - | (2) |
| Sales | - | - | - | - | - | - | - | - |
| End of 2014 | - | - | - | - | - | 53 | - | 53 |
| Revisions | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (3) | - | (3) |
| Sales | - | - | - | - | - | - | - | - |
| End of 2015 | - | - | - | - | - | 50 | - | 50 |
| Revisions | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (3) | - | (3) |
| Sales | - | - | - | - | - | - | - | - |
| **End of 2016** | - | - | - | - | - | 47 | - | 47 |
| *Total company* | | | | | | | | |
| End of 2013 | 125 | 462 | 587 | 56 | 28 | 59 | 14 | 744 |
| End of 2014 | 120 | 440 | 560 | 65 | 24 | 66 | - | 715 |
| End of 2015 | 114 | 321 | 435 | 45 | 20 | 58 | - | 558 |
| **End of 2016** | 107 | 278 | 385 | 48 | 19 | 52 | - | 504 |

| Years Ended December 31 | Natural Gas Liquids | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
| **Developed** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| End of 2013 | 125 | 362 | 487 | 50 | 19 | 13 | 14 | 583 |
| End of 2014 | 120 | 337 | 457 | 57 | 18 | 11 | - | 543 |
| End of 2015 | 114 | 235 | 349 | 45 | 16 | 8 | - | 418 |
| **End of 2016** | 107 | 209 | 316 | 47 | 15 | 5 | - | 383 |
| *Equity affiliates* | | | | | | | | |
| End of 2013 | - | - | - | - | - | 45 | - | 45 |
| End of 2014 | - | - | - | - | - | 53 | - | 53 |
| End of 2015 | - | - | - | - | - | 50 | - | 50 |
| **End of 2016** | - | - | - | - | - | 47 | - | 47 |
| **Undeveloped** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| End of 2013 | - | 100 | 100 | 6 | 9 | 1 | - | 116 |
| End of 2014 | - | 103 | 103 | 8 | 6 | 2 | - | 119 |
| End of 2015 | - | 86 | 86 | - | 4 | - | - | 90 |
| **End of 2016** | - | 69 | 69 | 1 | 4 | - | - | 74 |
| *Equity affiliates* | | | | | | | | |
| End of 2013 | - | - | - | - | - | - | - | - |
| End of 2014 | - | - | - | - | - | - | - | - |
| End of 2015 | - | - | - | - | - | - | - | - |
| **End of 2016** | - | - | - | - | - | - | - | - |

Notable changes in proved natural gas liquids reserves in the three years ended December 31, 2016, included:

- *Revisions*: In 2015, revisions in Lower 48 and Canada were primarily due to lower prices.

- *Extensions and discoveries*: In 2014, extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford and Bakken.

| Years Ended December 31 | Natural Gas | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Billions of Cubic Feet | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
| **Developed and Undeveloped** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| End of 2013 | 2,865 | 6,711 | 9,576 | 1,878 | 1,809 | 2,046 | 950 | 16,259 |
| Revisions | (75) | 581 | 506 | 225 | (54) | 115 | - | 792 |
| Improved recovery | - | - | - | - | - | 3 | - | 3 |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 7 | 256 | 263 | 85 | - | 3 | - | 351 |
| Production | (78) | (601) | (679) | (259) | (182) | (289) | (34) | (1,443) |
| Sales | - | (2) | (2) | (13) | - | - | (689) | (704) |
| End of 2014 | 2,719 | 6,945 | 9,664 | 1,916 | 1,573 | 1,878 | 227 | 15,258 |
| Revisions | (293) | (884) | (1,177) | (111) | (27) | 110 | - | (1,205) |
| Improved recovery | - | - | - | 1 | - | 8 | - | 9 |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 4 | 103 | 107 | 44 | - | 2 | - | 153 |
| Production | (83) | (588) | (671) | (261) | (187) | (285) | - | (1,404) |
| Sales | - | (405) | (405) | (482) | - | - | - | (887) |
| End of 2015 | 2,347 | 5,171 | 7,518 | 1,107 | 1,359 | 1,713 | 227 | 11,924 |
| Revisions | (105) | (124) | (229) | 111 | 56 | 18 | - | (44) |
| Improved recovery | - | - | - | - | - | 1 | - | 1 |
| Purchases | - | - | - | 1 | - | - | - | 1 |
| Extensions and discoveries | 2 | 162 | 164 | 43 | - | 124 | - | 331 |
| Production | (73) | (494) | (567) | (192) | (177) | (288) | - | (1,224) |
| Sales | (69) | (1) | (70) | (33) | - | (42) | - | (145) |
| **End of 2016** | 2,102 | 4,714 | 6,816 | 1,037 | 1,238 | 1,526 | 227 | 10,844 |
| | | | | | | | | |
| *Equity affiliates* | | | | | | | | |
| End of 2013 | - | - | - | - | - | 4,129 | - | 4,129 |
| Revisions | - | - | - | - | - | 768 | - | 768 |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 531 | - | 531 |
| Production | - | - | - | - | - | (186) | - | (186) |
| Sales | - | - | - | - | - | - | - | - |
| End of 2014 | - | - | - | - | - | 5,242 | - | 5,242 |
| Revisions | - | - | - | - | - | (2) | - | (2) |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 268 | - | 268 |
| Production | - | - | - | - | - | (239) | - | (239) |
| Sales | - | - | - | - | - | - | - | - |
| End of 2015 | - | - | - | - | - | 5,269 | - | 5,269 |
| Revisions | - | - | - | - | - | (676) | - | (676) |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 125 | - | 125 |
| Production | - | - | - | - | - | (337) | - | (337) |
| Sales | - | - | - | - | - | - | - | - |
| **End of 2016** | - | - | - | - | - | 4,381 | - | 4,381 |
| | | | | | | | | |
| *Total company* | | | | | | | | |
| End of 2013 | 2,865 | 6,711 | 9,576 | 1,878 | 1,809 | 6,175 | 950 | 20,388 |
| End of 2014 | 2,719 | 6,945 | 9,664 | 1,916 | 1,573 | 7,120 | 227 | 20,500 |
| End of 2015 | 2,347 | 5,171 | 7,518 | 1,107 | 1,359 | 6,982 | 227 | 17,193 |
| **End of 2016** | 2,102 | 4,714 | 6,816 | 1,037 | 1,238 | 5,907 | 227 | 15,225 |

| Years Ended December 31 | Natural Gas | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Billions of Cubic Feet | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
| **Developed** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| End of 2013 | 2,815 | 5,822 | 8,637 | 1,786 | 1,276 | 1,593 | 881 | 14,173 |
| End of 2014 | 2,663 | 5,922 | 8,585 | 1,801 | 1,182 | 1,553 | 226 | 13,347 |
| End of 2015 | 2,313 | 4,458 | 6,771 | 1,101 | 1,088 | 1,421 | 227 | 10,608 |
| **End of 2016** | 2,094 | 4,199 | 6,293 | 1,031 | 998 | 1,188 | 227 | 9,737 |
| *Equity affiliates* | | | | | | | | |
| End of 2013 | - | - | - | - | - | 2,606 | - | 2,606 |
| End of 2014 | - | - | - | - | - | 3,954 | - | 3,954 |
| End of 2015 | - | - | - | - | - | 4,482 | - | 4,482 |
| **End of 2016** | - | - | - | - | - | 4,110 | - | 4,110 |
| **Undeveloped** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| End of 2013 | 50 | 889 | 939 | 92 | 533 | 453 | 69 | 2,086 |
| End of 2014 | 56 | 1,023 | 1,079 | 115 | 391 | 325 | 1 | 1,911 |
| End of 2015 | 34 | 713 | 747 | 6 | 271 | 292 | - | 1,316 |
| **End of 2016** | 8 | 515 | 523 | 6 | 240 | 338 | - | 1,107 |
| *Equity affiliates* | | | | | | | | |
| End of 2013 | - | - | - | - | - | 1,523 | - | 1,523 |
| End of 2014 | - | - | - | - | - | 1,288 | - | 1,288 |
| End of 2015 | - | - | - | - | - | 787 | - | 787 |
| **End of 2016** | - | - | - | - | - | 271 | - | 271 |

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed in production operations.

Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Notable changes in proved natural gas reserves in the three years ended December 31, 2016, included:

- Revisions: In 2016, revisions in our equity affiliates in Asia Pacific/Middle East were primarily due to lower prices. In 2015, revisions in Lower 48, Alaska and Canada were primarily due to lower prices, partially offset by positive revisions in Asia Pacific/Middle East from Indonesia. In 2014, revisions were primarily due to higher prices, increased development activity and strong well performance in Lower 48 and higher prices and improved well performance in Canada and our consolidated operations in Asia Pacific/Middle East. This was partially offset by lower prices and higher costs in Alaska. For our equity affiliates in Asia Pacific/Middle East, 2014 revisions were primarily due to strong field performance.

- Extensions and discoveries: In 2015 and 2014, for our equity affiliates in Asia Pacific/Middle East, extensions and discoveries were due to APLNG's ongoing development drilling onshore Australia. In 2014, extensions and discoveries in Lower 48 and Canada were primarily due to continued drilling success in Eagle Ford and Bakken and ongoing development activity in western Canada.

- Sales: In 2015, Lower 48 sales were due to the disposition of non-core assets in South Texas, East Texas and North Louisiana and sales of assets in British Columbia, Saskatchewan and Alberta impacted Canada. In 2014, for our consolidated operations in Africa, sales were due to the disposition of the Nigeria business.

| Years Ended December 31 | Bitumen Millions of Barrels Canada |
|---|---|
| **Developed and Undeveloped** | |
| *Consolidated operations* | |
| End of 2013 | 579 |
| Revisions | (8) |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 31 |
| Production | (4) |
| Sales | - |
| End of 2014 | 598 |
| Revisions | 94 |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | - |
| Production | (5) |
| Sales | - |
| End of 2015 | 687 |
| Revisions | (515) |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | - |
| Production | (13) |
| Sales | - |
| **End of 2016** | 159 |
| | |
| *Equity affiliates* | |
| End of 2013 | 1,451 |
| Revisions | (14) |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 74 |
| Production | (43) |
| Sales | - |
| End of 2014 | 1,468 |
| Revisions | 190 |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 99 |
| Production | (51) |
| Sales | - |
| End of 2015 | 1,706 |
| Revisions | (573) |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 10 |
| Production | (54) |
| Sales | - |
| **End of 2016** | 1,089 |
| | |
| *Total company* | |
| End of 2013 | 2,030 |
| End of 2014 | 2,066 |
| End of 2015 | 2,393 |
| **End of 2016** | 1,248 |

| Years Ended December 31 | Bitumen Millions of Barrels Canada |
|---|---|
| **Developed** | |
| *Consolidated operations* | |
| End of 2013 | 16 |
| End of 2014 | 13 |
| End of 2015 | 111 |
| **End of 2016** | 159 |
| *Equity affiliates* | |
| End of 2013 | 181 |
| End of 2014 | 187 |
| End of 2015 | 311 |
| **End of 2016** | 322 |
| **Undeveloped** | |
| *Consolidated operations* | |
| End of 2013 | 563 |
| End of 2014 | 585 |
| End of 2015 | 576 |
| **End of 2016** | - |
| *Equity affiliates* | |
| End of 2013 | 1,270 |
| End of 2014 | 1,281 |
| End of 2015 | 1,395 |
| **End of 2016** | 767 |

Notable changes in proved bitumen reserves in the three years ended December 31, 2016, included:

- Revisions: In 2016, for both our consolidated operations and equity affiliates revisions were primarily related to lower prices which resulted in reserve reductions at Surmont, Foster Creek, Christina Lake and Narrows Lake. In 2015, for both our consolidated operations and equity affiliates revisions were primarily related to reduced royalties from lower prices at Surmont, Foster Creek, Christina Lake and Narrows Lake.

- Extensions and discoveries: In 2015, for our equity affiliates extensions and discoveries were related to approval of development at Christina Lake. In 2014, for our consolidated operations extensions and discoveries were primarily related to delineation activity at Surmont. In 2014, for our equity affiliates extensions and discoveries were primarily related to delineation activity at Foster Creek and Christina Lake, as well as regulatory approval of a development area at Foster Creek.

| Years Ended December 31 | Total Proved Reserves | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels of Oil Equivalent | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed and Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2013 | 1,708 | 2,187 | 3,895 | 970 | 785 | 588 | 409 | - | 6,647 |
| Revisions | (19) | 109 | 90 | 48 | (10) | 26 | - | - | 154 |
| Improved recovery | 8 | - | 8 | 2 | - | 3 | - | - | 13 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 17 | 184 | 201 | 50 | - | 17 | - | - | 268 |
| Production | (78) | (206) | (284) | (61) | (78) | (81) | (11) | - | (515) |
| Sales | - | - | - | (3) | - | - | (156) | - | (159) |
| End of 2014 | 1,636 | 2,274 | 3,910 | 1,006 | 697 | 553 | 242 | - | 6,408 |
| Revisions | (165) | (301) | (466) | 66 | (26) | (12) | - | - | (438) |
| Improved recovery | 4 | 4 | 8 | 2 | - | 32 | - | - | 42 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 20 | 84 | 104 | 10 | - | 8 | - | - | 122 |
| Production | (75) | (211) | (286) | (62) | (78) | (84) | - | - | (510) |
| Sales | - | (79) | (79) | (92) | - | - | - | - | (171) |
| End of 2015 | 1,420 | 1,771 | 3,191 | 930 | 593 | 497 | 242 | - | 5,453 |
| Revisions | (77) | (143) | (220) | (484) | 11 | 9 | - | - | (684) |
| Improved recovery | 6 | 3 | 9 | - | - | 7 | - | - | 16 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 33 | 124 | 157 | 9 | - | 28 | - | - | 194 |
| Production | (76) | (185) | (261) | (55) | (76) | (87) | (1) | - | (480) |
| Sales | (12) | - | (12) | (7) | - | (10) | - | - | (29) |
| **End of 2016** | 1,294 | 1,570 | 2,864 | 393 | 528 | 444 | 241 | - | 4,470 |
| *Equity affiliates* | | | | | | | | | |
| End of 2013 | - | - | - | 1,451 | - | 819 | - | 4 | 2,274 |
| Revisions | - | - | - | (14) | - | 155 | - | 3 | 144 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | 74 | - | 89 | - | - | 163 |
| Production | - | - | - | (43) | - | (38) | - | (2) | (83) |
| Sales | - | - | - | - | - | - | - | - | - |
| End of 2014 | - | - | - | 1,468 | - | 1,025 | - | 5 | 2,498 |
| Revisions | - | - | - | 190 | - | (1) | - | - | 189 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | 99 | - | 45 | - | - | 144 |
| Production | - | - | - | (51) | - | (48) | - | (1) | (100) |
| Sales | - | - | - | - | - | - | - | (4) | (4) |
| End of 2015 | - | - | - | 1,706 | - | 1,021 | - | - | 2,727 |
| Revisions | - | - | - | (573) | - | (113) | - | - | (686) |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | 10 | - | 21 | - | - | 31 |
| Production | - | - | - | (54) | - | (64) | - | - | (118) |
| Sales | - | - | - | - | - | - | - | - | - |
| **End of 2016** | - | - | - | 1,089 | - | 865 | - | - | 1,954 |
| *Total company* | | | | | | | | | |
| End of 2013 | 1,708 | 2,187 | 3,895 | 2,421 | 785 | 1,407 | 409 | 4 | 8,921 |
| End of 2014 | 1,636 | 2,274 | 3,910 | 2,474 | 697 | 1,578 | 242 | 5 | 8,906 |
| End of 2015 | 1,420 | 1,771 | 3,191 | 2,636 | 593 | 1,518 | 242 | - | 8,180 |
| **End of 2016** | 1,294 | 1,570 | 2,864 | 1,482 | 528 | 1,309 | 241 | - | 6,424 |

| Years Ended December 31 | Total Proved Reserves | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels of Oil Equivalent | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2013 | 1,597 | 1,600 | 3,197 | 386 | 478 | 405 | 391 | - | 4,857 |
| End of 2014 | 1,514 | 1,637 | 3,151 | 393 | 452 | 412 | 237 | - | 4,645 |
| End of 2015 | 1,318 | 1,261 | 2,579 | 352 | 398 | 384 | 242 | - | 3,955 |
| **End of 2016** | 1,203 | 1,165 | 2,368 | 391 | 365 | 309 | 241 | - | 3,674 |
| *Equity affiliates* | | | | | | | | | |
| End of 2013 | - | - | - | 181 | - | 565 | - | 4 | 750 |
| End of 2014 | - | - | - | 187 | - | 810 | - | 5 | 1,002 |
| End of 2015 | - | - | - | 311 | - | 890 | - | - | 1,201 |
| **End of 2016** | - | - | - | 322 | - | 820 | - | - | 1,142 |
| **Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2013 | 111 | 587 | 698 | 584 | 307 | 183 | 18 | - | 1,790 |
| End of 2014 | 122 | 637 | 759 | 613 | 245 | 141 | 5 | - | 1,763 |
| End of 2015 | 102 | 510 | 612 | 578 | 195 | 113 | - | - | 1,498 |
| **End of 2016** | 91 | 405 | 496 | 2 | 163 | 135 | - | - | 796 |
| *Equity affiliates* | | | | | | | | | |
| End of 2013 | - | - | - | 1,270 | - | 254 | - | - | 1,524 |
| End of 2014 | - | - | - | 1,281 | - | 215 | - | - | 1,496 |
| End of 2015 | - | - | - | 1,395 | - | 131 | - | - | 1,526 |
| **End of 2016** | - | - | - | 767 | - | 45 | - | - | 812 |

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE.

## Proved Undeveloped Reserves

We had 1,608 million BOE of proved undeveloped reserves at year-end 2016, compared with 3,024 million BOE at year-end 2015. The following table shows changes in total proved undeveloped reserves for 2016:

| | Proved Undeveloped Reserves |
|---|---|
| | Millions of Barrels of Oil Equivalent |
| End of 2015 | 3,024 |
| Transfers to proved developed | (310) |
| Revisions | (1,328) |
| Improved recovery | 13 |
| Purchases | - |
| Extensions and discoveries | 212 |
| Sales | (3) |
| **End of 2016** | 1,608 |

Revisions, primarily in the oil sands, decreased proved undeveloped reserves due to lower prices. This was partially offset by extensions and discoveries added from ongoing development primarily in the Lower 48, Asia Pacific/Middle East and Alaska.

As a result, at December 31, 2016, our proved undeveloped reserves represented 25 percent of total proved reserves, compared with 37 percent at December 31, 2015. Costs incurred for the year ended December 31, 2016, relating to the development of proved undeveloped reserves were $2.9 billion. A portion of our costs incurred each year relate to development projects where the proved undeveloped reserves will be converted to proved developed reserves in future years.

Approximately 70 percent of our proved undeveloped reserves at year-end 2016 were associated with four major development areas. All of the major development areas are currently producing and are expected to have proved undeveloped reserves convert to proved developed over time, as development activities continue and/or production facilities are expanded or upgraded, and include:

- FCCL oil sands—Foster Creek and Christina Lake in Canada.
- The Eagle Ford and Bakken areas in the Lower 48.

At the end of 2016, approximately 46 percent of our total proved undeveloped reserves are currently scheduled for development five years or more from initial disclosure which are located in the Athabasca oil sands in Canada. The oil sands in Canada consist of the FCCL and Surmont steam-assisted gravity drainage (SAGD) projects. The majority of our remaining proved undeveloped reserves in this area were recorded beginning in 2007. Our SAGD projects are large, multi-year projects with steady, long-term production at consistent levels. The associated undeveloped reserves are expected to be developed over the life of the project, as additional well pairs are drilled to maintain throughput at the central processing facilities.

**Results of Operations**

The company's results of operations from oil and gas activities for the years 2016, 2015 and 2014 are shown in the following tables. Non-oil and gas activities, such as pipeline and marine operations, liquefied natural gas operations, crude oil and gas marketing activities, and the profit element of transportation operations in which we have an ownership interest are excluded. Additional information about selected line items within the results of operations tables is shown below:

- Sales include sales to unaffiliated entities attributable primarily to the company's net working interests and royalty interests. Sales are net of fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are not consolidated.

- Transportation costs reflect fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are consolidated.

- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.

- Production costs include costs incurred to operate and maintain wells, related equipment and facilities used in the production of petroleum liquids and natural gas.

- Taxes other than income taxes include production, property and other non-income taxes.

- Depreciation of support equipment is reclassified as applicable.

- Other related expenses include inventory fluctuations, foreign currency transaction gains and losses and other miscellaneous expenses.

## Results of Operations

| Year Ended December 31, 2016 | | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| *Consolidated operations* | | | | | | | | | | |
| Sales | $ | 2,793 | 4,117 | 6,910 | 661 | 2,678 | 2,350 | - | - | 12,599 |
| Transfers | | 8 | - | 8 | - | - | 347 | - | - | 355 |
| Transportation costs | | (676) | - | (676) | - | - | (40) | - | - | (716) |
| Other revenues | | 375 | 111 | 486 | 48 | (34) | (25) | 147 | 9 | 631 |
| Total revenues | | 2,500 | 4,228 | 6,728 | 709 | 2,644 | 2,632 | 147 | 9 | 12,869 |
| Production costs excluding taxes | | 1,056 | 1,967 | 3,023 | 790 | 795 | 640 | 23 | (2) | 5,269 |
| Taxes other than income taxes | | 231 | 308 | 539 | 55 | 31 | 30 | 1 | - | 656 |
| Exploration expenses | | 45 | 1,227 | 1,272 | 332 | 90 | 38 | 138 | 41 | 1,911 |
| Depreciation, depletion and amortization | | 738 | 4,167 | 4,905 | 881 | 1,390 | 1,402 | 2 | - | 8,580 |
| Impairments | | 1 | 148 | 149 | 88 | (161) | 44 | - | - | 120 |
| Other related expenses | | 52 | 70 | 122 | (51) | (77) | (13) | 4 | 4 | (11) |
| Accretion | | 52 | 72 | 124 | 32 | 210 | 35 | - | - | 401 |
| | | 325 | (3,731) | (3,406) | (1,418) | 366 | 456 | (21) | (34) | (4,057) |
| Income tax provision (benefit) | | (29) | (1,349) | (1,378) | (406) | 3 | 250 | (72) | (13) | (1,616) |
| Results of operations | $ | 354 | (2,382) | (2,028) | (1,012) | 363 | 206 | 51 | (21) | (2,441) |
| | | | | | | | | | | |
| *Equity affiliates* | | | | | | | | | | |
| Sales | $ | - | - | - | 860 | - | 449 | - | - | 1,309 |
| Transfers | | - | - | - | - | - | 825 | - | - | 825 |
| Transportation costs | | - | - | - | - | - | - | - | - | - |
| Other revenues | | - | - | - | - | - | (2) | - | - | (2) |
| Total revenues | | - | - | - | 860 | - | 1,272 | - | - | 2,132 |
| Production costs excluding taxes | | - | - | - | 431 | - | 256 | - | - | 687 |
| Taxes other than income taxes | | - | - | - | 15 | - | 476 | - | - | 491 |
| Exploration expenses | | - | - | - | 6 | - | - | - | - | 6 |
| Depreciation, depletion and amortization | | - | - | - | 309 | - | 548 | - | - | 857 |
| Impairments | | - | - | - | 9 | - | - | - | - | 9 |
| Other related expenses | | - | - | - | (7) | - | 8 | - | 24 | 25 |
| Accretion | | - | - | - | 8 | - | 7 | - | - | 15 |
| | | - | - | - | 89 | - | (23) | - | (24) | 42 |
| Income tax provision (benefit) | | - | - | - | 24 | - | (201) | - | - | (177) |
| Results of operations | $ | - | - | - | 65 | - | 178 | - | (24) | 219 |

| Year Ended December 31, 2015 | | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| *Consolidated operations* | | | | | | | | | | |
| Sales | $ | 3,206 | 4,992 | 8,198 | 930 | 3,637 | 2,741 | - | - | 15,506 |
| Transfers | | 15 | - | 15 | - | - | 629 | - | - | 644 |
| Transportation costs | | (599) | - | (599) | - | - | (40) | - | - | (639) |
| Other revenues | | (5) | 452 | 447 | (19) | (28) | 6 | 13 | 2 | 421 |
| Total revenues | | 2,617 | 5,444 | 8,061 | 911 | 3,609 | 3,336 | 13 | 2 | 15,932 |
| Production costs excluding taxes | | 1,242 | 2,420 | 3,662 | 923 | 1,137 | 815 | 42 | 1 | 6,580 |
| Taxes other than income taxes | | 281 | 358 | 639 | 62 | 35 | 33 | 3 | 1 | 773 |
| Exploration expenses | | 682 | 1,583 | 2,265 | 457 | 170 | 268 | 990 | 43 | 4,193 |
| Depreciation, depletion and amortization | | 548 | 4,192 | 4,740 | 777 | 1,813 | 1,321 | - | - | 8,651 |
| Impairments | | 8 | (2) | 6 | 3 | 724 | 3 | - | - | 736 |
| Other related expenses | | (30) | 78 | 48 | 8 | 9 | (2) | (8) | 5 | 60 |
| Accretion | | 52 | 83 | 135 | 49 | 240 | 34 | - | - | 458 |
| | | (166) | (3,268) | (3,434) | (1,368) | (519) | 864 | (1,014) | (48) | (5,519) |
| Income tax provision (benefit) | | (89) | (1,193) | (1,282) | (244) | (816) | 430 | (406) | (27) | (2,345) |
| Results of operations | $ | (77) | (2,075) | (2,152) | (1,124) | 297 | 434 | (608) | (21) | (3,174) |
| | | | | | | | | | | |
| *Equity affiliates* | | | | | | | | | | |
| Sales | $ | - | - | - | 917 | - | 536 | - | 50 | 1,503 |
| Transfers | | - | - | - | - | - | 950 | - | - | 950 |
| Transportation costs | | - | - | - | - | - | - | - | - | - |
| Other revenues | | - | - | - | 34 | - | 4 | - | 58 | 96 |
| Total revenues | | - | - | - | 951 | - | 1,490 | - | 108 | 2,549 |
| Production costs excluding taxes | | - | - | - | 474 | - | 248 | - | 13 | 735 |
| Taxes other than income taxes | | - | - | - | 15 | - | 723 | - | 13 | 751 |
| Exploration expenses | | - | - | - | 12 | - | 190 | - | - | 202 |
| Depreciation, depletion and amortization | | - | - | - | 367 | - | 197 | - | 5 | 569 |
| Impairments | | - | - | - | - | - | 1,396 | - | 3 | 1,399 |
| Other related expenses | | - | - | - | (2) | - | (13) | - | 23 | 8 |
| Accretion | | - | - | - | 7 | - | 10 | - | 1 | 18 |
| | | - | - | - | 78 | - | (1,261) | - | 50 | (1,133) |
| Income tax provision (benefit) | | - | - | - | 20 | - | (155) | - | 10 | (125) |
| Results of operations | $ | - | - | - | 58 | - | (1,106) | - | 40 | (1,008) |

| Year Ended December 31, 2014 | | Millions of Dollars | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Disc Ops | Total |
| *Consolidated operations* | | | | | | | | | | | |
| Sales | $ | 6,202 | 9,098 | 15,300 | 2,091 | 6,160 | 4,550 | 185 | - | 278 | 28,564 |
| Transfers | | 47 | 94 | 141 | - | - | 938 | - | - | - | 1,079 |
| Transportation costs | | (659) | - | (659) | - | - | (43) | - | - | - | (702) |
| Other revenues | | 13 | 29 | 42 | 185 | (25) | 46 | 26 | 154 | 1,052 | 1,480 |
| Total revenues | | 5,603 | 9,221 | 14,824 | 2,276 | 6,135 | 5,491 | 211 | 154 | 1,330 | 30,421 |
| Production costs excluding taxes | | 1,205 | 2,482 | 3,687 | 1,106 | 1,410 | 994 | 83 | 1 | 128 | 7,409 |
| Taxes other than income taxes | | 842 | 700 | 1,542 | 62 | 44 | 299 | 5 | 1 | 8 | 1,961 |
| Exploration expenses | | 46 | 1,042 | 1,088 | 317 | 148 | 123 | 303 | 40 | 4 | 2,023 |
| Depreciation, depletion and amortization | | 423 | 3,662 | 4,085 | 919 | 1,777 | 1,125 | 6 | - | - | 7,912 |
| Impairments | | 56 | 107 | 163 | 38 | 529 | 7 | - | - | - | 737 |
| Other related expenses | | 2 | 96 | 98 | 7 | (233) | (6) | (1) | 9 | (9) | (135) |
| Accretion | | 52 | 80 | 132 | 57 | 245 | 26 | - | - | - | 460 |
| | | 2,977 | 1,052 | 4,029 | (230) | 2,215 | 2,923 | (185) | 103 | 1,199 | 10,054 |
| Income tax provision (benefit) | | 1,043 | 322 | 1,365 | (101) | 1,452 | 1,216 | 4 | (13) | 79 | 4,002 |
| Results of operations | $ | 1,934 | 730 | 2,664 | (129) | 763 | 1,707 | (189) | 116 | 1,120 | 6,052 |
| | | | | | | | | | | | |
| *Equity affiliates* | | | | | | | | | | | |
| Sales | $ | - | - | - | 2,307 | - | 851 | - | 96 | - | 3,254 |
| Transfers | | - | - | - | - | - | 1,663 | - | - | - | 1,663 |
| Transportation costs | | - | - | - | - | - | - | - | - | - | - |
| Other revenues | | - | - | - | 33 | - | 3 | - | - | - | 36 |
| Total revenues | | - | - | - | 2,340 | - | 2,517 | - | 96 | - | 4,953 |
| Production costs excluding taxes | | - | - | - | 651 | - | 221 | - | 18 | - | 890 |
| Taxes other than income taxes | | - | - | - | 14 | - | 1,214 | - | 51 | - | 1,279 |
| Exploration expenses | | - | - | - | 13 | 7 | 8 | - | - | - | 28 |
| Depreciation, depletion and amortization | | - | - | - | 337 | - | 171 | - | 7 | - | 515 |
| Impairments | | - | - | - | - | - | 27 | - | - | - | 27 |
| Other related expenses | | - | - | - | (65) | 1 | (2) | - | 27 | - | (39) |
| Accretion | | - | - | - | 6 | - | 8 | - | 1 | - | 15 |
| | | - | - | - | 1,384 | (8) | 870 | - | (8) | - | 2,238 |
| Income tax provision (benefit) | | - | - | - | 331 | - | (62) | - | 2 | - | 271 |
| Results of operations | $ | - | - | - | 1,053 | (8) | 932 | - | (10) | - | 1,967 |

**Statistics**

| **Net Production** | **2016** | 2015 | 2014 |
|---|---|---|---|
| | Thousands of Barrels Daily | | |
| **Crude Oil** | | | |
| *Consolidated operations* | | | |
| Alaska | **163** | 158 | 162 |
| Lower 48 | **195** | 206 | 188 |
| United States | **358** | 364 | 350 |
| Canada | **7** | 12 | 13 |
| Europe | **120** | 120 | 126 |
| Asia Pacific/Middle East | **97** | 91 | 79 |
| Africa | **2** | - | 8 |
| Total consolidated operations | **584** | 587 | 576 |
| *Equity affiliates* | | | |
| Asia Pacific/Middle East | **14** | 14 | 15 |
| Other areas | **-** | 4 | 4 |
| Total equity affiliates | **14** | 18 | 19 |
| Total continuing operations | **598** | 605 | 595 |
| Discontinued operations | **-** | - | 5 |
| Total company | **598** | 605 | 600 |
| **Natural Gas Liquids** | | | |
| *Consolidated operations* | | | |
| Alaska | **12** | 13 | 13 |
| Lower 48 | **88** | 94 | 97 |
| United States | **100** | 107 | 110 |
| Canada | **23** | 26 | 23 |
| Europe | **7** | 7 | 8 |
| Asia Pacific/Middle East | **7** | 9 | 10 |
| Total consolidated operations | **137** | 149 | 151 |
| *Equity affiliates*—Asia Pacific/Middle East | **8** | 7 | 8 |
| Total continuing operations | **145** | 156 | 159 |
| Discontinued operations | **-** | - | 1 |
| Total company | **145** | 156 | 160 |
| **Bitumen** | | | |
| *Consolidated operations*—Canada | **35** | 13 | 12 |
| *Equity affiliates*—Canada | **148** | 138 | 117 |
| Total company | **183** | 151 | 129 |
| **Natural Gas** | Millions of Cubic Feet Daily | | |
| *Consolidated operations* | | | |
| Alaska | **25** | 42 | 49 |
| Lower 48 | **1,219** | 1,472 | 1,491 |
| United States | **1,244** | 1,514 | 1,540 |
| Canada | **524** | 715 | 711 |
| Europe | **459** | 475 | 461 |
| Asia Pacific/Middle East | **730** | 717 | 723 |
| Africa | **1** | 1 | 3 |
| Total consolidated operations | **2,958** | 3,422 | 3,438 |
| *Equity affiliates*—Asia Pacific/Middle East | **899** | 638 | 505 |
| Total continuing operations | **3,857** | 4,060 | 3,943 |
| Discontinued operations | **-** | - | 88 |
| Total company | **3,857** | 4,060 | 4,031 |

| Average Sales Prices | | 2016 | 2015 | 2014 |
|---|---|---|---|---|
| **Crude Oil Per Barrel** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **31.68** | 41.84 | 87.21 |
| Lower 48 | | **37.49** | 42.62 | 84.18 |
| United States | | **34.70** | 42.27 | 85.63 |
| Canada | | **35.25** | 39.52 | 77.87 |
| Europe | | **43.66** | 52.75 | 99.56 |
| Asia Pacific/Middle East | | **42.23** | 49.70 | 95.32 |
| Africa | | **-** | 60.79 | 86.71 |
| Total international | | **42.76** | 50.79 | 96.48 |
| Total consolidated operations | | **37.67** | 45.48 | 89.72 |
| *Equity affiliates* | | | | |
| Asia Pacific/Middle East | | **44.11** | 53.12 | 99.01 |
| Other areas | | **-** | 37.21 | 64.14 |
| Total equity affiliates | | **44.11** | 49.92 | 91.48 |
| Total continuing operations | | **37.82** | 45.61 | 89.77 |
| *Discontinued operations* | | **-** | - | 110.61 |
| **Natural Gas Liquids Per Barrel** | | | | |
| *Consolidated operations* | | | | |
| Lower 48 | $ | **14.34** | 14.01 | 30.74 |
| United States | | **14.34** | 14.01 | 30.74 |
| Canada | | **14.82** | 17.02 | 46.23 |
| Europe | | **22.62** | 27.56 | 52.65 |
| Asia Pacific/Middle East | | **29.00** | 37.78 | 69.36 |
| Total international | | **19.06** | 23.21 | 53.26 |
| Total consolidated operations | | **15.72** | 16.83 | 37.45 |
| *Equity affiliates*—Asia Pacific/Middle East | | **31.13** | 35.79 | 67.20 |
| Total continuing operations | | **16.68** | 17.79 | 38.99 |
| *Discontinued operations* | | **-** | - | 13.41 |
| **Bitumen Per Barrel** | | | | |
| *Consolidated operations*—Canada | $ | **12.91** | 20.13 | 60.03 |
| *Equity affiliates*—Canada | | **15.80** | 18.58 | 54.62 |
| **Natural Gas Per Thousand Cubic Feet** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **5.22** | 4.33 | 5.42 |
| Lower 48 | | **2.20** | 2.43 | 4.29 |
| United States | | **2.24** | 2.47 | 4.32 |
| Canada | | **1.49** | 1.91 | 4.13 |
| Europe | | **4.71** | 7.14 | 9.29 |
| Asia Pacific/Middle East | | **4.15** | 6.08 | 9.64 |
| Africa | | **-** | - | 3.40 |
| Total international | | **3.49** | 4.78 | 7.48 |
| Total consolidated operations | | **2.97** | 3.77 | 6.07 |
| *Equity affiliates*—Asia Pacific/Middle East | | **2.97** | 4.83 | 9.79 |
| Total continuing operations | | **2.97** | 3.93 | 6.54 |
| *Discontinued operations* | | **-** | - | 2.53 |

*Average sales prices for Alaska crude oil and Asia Pacific/Middle East natural gas above reflect a reduction for transportation costs in which we have an ownership interest that are incurred subsequent to the terminal point of the production function. Accordingly, the average sales prices differ from those discussed in Item 7 of Management's Discussion and Analysis of Financial Condition and Results of Operations.*

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| **Average Production Costs Per Barrel of Oil Equivalent*** | | | |
| *Consolidated operations* | | | |
| Alaska | $ **16.12** | 19.12 | 18.04 |
| Lower 48 | **11.06** | 12.17 | 12.76 |
| United States | **12.42** | 13.88 | 14.11 |
| Canada | **14.20** | 14.88 | 18.14 |
| Europe | **10.70** | 15.05 | 18.31 |
| Asia Pacific/Middle East | **7.74** | 10.20 | 12.97 |
| Africa | **31.42** | - | 28.42 |
| Total international | **10.53** | 13.41 | 16.52 |
| Total consolidated continuing operations | **11.54** | 13.67 | 15.20 |
| *Equity affiliates* | | | |
| Canada | **7.96** | 9.41 | 15.24 |
| Asia Pacific/Middle East | **4.04** | 5.31 | 5.66 |
| Other areas | **-** | 8.90 | 12.33 |
| Total equity affiliates | **5.85** | 7.46 | 10.69 |
| *Discontinued operations* | **-** | - | 16.70 |
| **Average Production Costs Per Barrel—Bitumen** | | | |
| *Consolidated operations*—Canada** | $ **24.59** | 61.87 | 66.89 |
| *Equity affiliates*—Canada | **7.96** | 9.41 | 15.24 |
| **Taxes Other Than Income Taxes Per Barrel of Oil Equivalent** | | | |
| *Consolidated operations* | | | |
| Alaska | $ **3.53** | 4.33 | 12.61 |
| Lower 48 | **1.73** | 1.80 | 3.60 |
| United States | **2.21** | 2.42 | 5.90 |
| Canada | **0.99** | 1.00 | 1.02 |
| Europe | **0.42** | 0.46 | 0.57 |
| Asia Pacific/Middle East | **0.36** | 0.41 | 3.90 |
| Africa | **1.37** | - | 1.71 |
| Total international | **0.55** | 0.62 | 1.89 |
| Total consolidated continuing operations | **1.44** | 1.61 | 4.08 |
| *Equity affiliates* | | | |
| Canada | **0.28** | 0.30 | 0.33 |
| Asia Pacific/Middle East | **7.52** | 15.48 | 31.08 |
| Other areas | **-** | 8.90 | 34.93 |
| Total equity affiliates | **4.18** | 7.62 | 15.37 |
| *Discontinued operations* | **-** | - | 1.04 |
| **Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent** | | | |
| *Consolidated operations* | | | |
| Alaska | $ **11.26** | 8.43 | 6.33 |
| Lower 48 | **23.43** | 21.07 | 18.82 |
| United States | **20.15** | 17.96 | 15.63 |
| Canada | **15.84** | 12.52 | 15.08 |
| Europe | **18.71** | 24.00 | 23.07 |
| Asia Pacific/Middle East | **16.95** | 16.53 | 14.68 |
| Africa | **2.73** | - | 2.05 |
| Total international | **17.22** | 17.98 | 17.59 |
| Total consolidated continuing operations | **18.78** | 17.97 | 16.52 |
| *Equity affiliates* | | | |
| Canada | **5.70** | 7.29 | 7.89 |
| Asia Pacific/Middle East | **8.65** | 4.22 | 4.38 |
| Other areas | **-** | 3.42 | 4.79 |
| Total equity affiliates | **7.29** | 5.77 | 6.19 |

**Includes bitumen.*
***2015 revised to conform to current period presentation.*

## Development and Exploration Activities

The following two tables summarize our net interest in productive and dry exploratory and development wells in the years ended December 31, 2016, 2015 and 2014. A "development well" is a well drilled within the proved area of a reservoir to the depth of a stratigraphic horizon known to be productive. An "exploratory well" is a well drilled to find and produce crude oil or natural gas in an unknown field or a new reservoir within a proven field. Exploratory wells also include wells drilled in areas near or offsetting current production, or in areas where well density or production history have not achieved statistical certainty of results. Excluded from the exploratory well count are stratigraphic-type exploratory wells, primarily relating to oil sands delineation wells located in Canada and coalbed methane test wells located in Asia Pacific/Middle East.

| **Net Wells Completed** | Productive | | | Dry | | |
|---|---|---|---|---|---|---|
| | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| **Exploratory** | | | | | | |
| *Consolidated operations* | | | | | | |
| Alaska | **2** | - | * | **1** | - | * |
| Lower 48 | **8** | 47 | 30 | **1** | 4 | 3 |
| United States | **10** | 47 | 30 | **2** | 4 | 3 |
| Canada | **8** | 16 | 9 | **1** | 3 | * |
| Europe | * | * | 1 | **1** | * | 1 |
| Asia Pacific/Middle East | **1** | 1 | 2 | **-** | 2 | * |
| Africa | **1** | * | * | **-** | * | * |
| Other areas | **-** | - | - | **-** | - | - |
| Total consolidated operations | **20** | 64 | 42 | **4** | 9 | 4 |
| *Equity affiliates* | | | | | | |
| Asia Pacific/Middle East | **20** | 19 | 36 | **-** | * | 2 |
| Total equity affiliates | **20** | 19 | 36 | **-** | - | 2 |
| | | | | | | |
| **Development** | | | | | | |
| *Consolidated operations* | | | | | | |
| Alaska | **9** | 18 | 8 | **-** | - | - |
| Lower 48 | **119** | 347 | 450 | **-** | - | 1 |
| United States | **128** | 365 | 458 | **-** | - | 1 |
| Canada | **47** | 47 | 98 | **2** | - | - |
| Europe | **7** | 10 | 7 | **-** | - | - |
| Asia Pacific/Middle East | **6** | 3 | 14 | **-** | * | - |
| Africa | **-** | - | 1 | **-** | - | - |
| Other areas | **-** | - | - | **-** | - | - |
| Total consolidated operations | **188** | 425 | 578 | **2** | - | 1 |
| *Equity affiliates* | | | | | | |
| Canada | **48** | 22 | 38 | **-** | - | - |
| Asia Pacific/Middle East | **108** | 166 | 294 | **-** | 2 | 1 |
| Other areas | **-** | * | 1 | **-** | - | - |
| Total equity affiliates | **156** | 188 | 333 | **-** | 2 | 1 |

**Our total proportionate interest was less than one.*

The table below represents the status of our wells drilling at December 31, 2016, and includes wells in the process of drilling or in active completion. It also represents gross and net productive wells, including producing wells and wells capable of production at December 31, 2016.

| **Wells at December 31, 2016** | | | Productive* | | | |
|---|---|---|---|---|---|---|
| | In Progress | | Oil | | Gas | |
| | Gross | Net | Gross | Net | Gross | Net |
| *Consolidated operations* | | | | | | |
| Alaska | 2 | 1 | 1,749 | 781 | - | - |
| Lower 48 | 208 | 94 | 10,142 | 5,107 | 20,076 | 13,134 |
| United States | 210 | 95 | 11,891 | 5,888 | 20,076 | 13,134 |
| Canada | 41 | 24 | 987 | 538 | 4,320 | 2,966 |
| Europe | 20 | 3 | 471 | 86 | 174 | 67 |
| Asia Pacific/Middle East | 13 | 5 | 356 | 148 | 55 | 28 |
| Africa | - | - | 825 | 135 | 9 | 1 |
| Other areas | 3 | 2 | - | - | - | - |
| Total consolidated operations | 287 | 129 | 14,530 | 6,795 | 24,634 | 16,196 |
| *Equity affiliates* | | | | | | |
| Canada | 125 | 62 | 457 | 228 | - | - |
| Asia Pacific/Middle East | 187 | 64 | - | - | 3,520 | 827 |
| Total equity affiliates | 312 | 126 | 457 | 228 | 3,520 | 827 |

**Includes 151 gross and 122 net multiple completion wells.*

| **Acreage at December 31, 2016** | Thousands of Acres | | | |
|---|---|---|---|---|
| | Developed | | Undeveloped | |
| | Gross | Net | Gross | Net |
| *Consolidated operations* | | | | |
| Alaska | 608 | 298 | 683 | 469 |
| Lower 48 | 4,903 | 3,918 | 10,479 | 8,475 |
| United States | 5,511 | 4,216 | 11,162 | 8,944 |
| Canada | 3,038 | 2,099 | 9,471 | 4,165 |
| Europe | 834 | 257 | 2,219 | 610 |
| Asia Pacific/Middle East | 1,593 | 741 | 10,483 | 5,422 |
| Africa | 358 | 58 | 12,545 | 2,049 |
| Other areas | - | - | 487 | 264 |
| Total consolidated operations | 11,334 | 7,371 | 46,367 | 21,454 |
| *Equity affiliates* | | | | |
| Canada | 53 | 22 | 651 | 273 |
| Asia Pacific/Middle East | 818 | 183 | 6,365 | 1,794 |
| Total equity affiliates | 871 | 205 | 7,016 | 2,067 |

## Costs Incurred

| Year Ended December 31 | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East * | Africa | Other Areas | Total |
| **2016** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Unproved property acquisition | $ - | 127 | 127 | 59 | - | - | - | - | 186 |
| Proved property acquisition | - | 5 | 5 | 19 | - | - | - | - | 24 |
| | - | 132 | 132 | 78 | - | - | - | - | 210 |
| Exploration | 110 | 656 | 766 | 286 | 65 | 52 | 215 | 67 | 1,451 |
| Development | 720 | 782 | 1,502 | 209 | 62 | 387 | 6 | - | 2,166 |
| | $ 830 | 1,570 | 2,400 | 573 | 127 | 439 | 221 | 67 | 3,827 |
| *Equity affiliates* | | | | | | | | | |
| Unproved property acquisition | $ - | - | - | - | - | 2 | - | - | 2 |
| Proved property acquisition | - | - | - | - | - | - | - | - | - |
| | - | - | - | - | - | 2 | - | - | 2 |
| Exploration | - | - | - | 15 | - | 19 | - | - | 34 |
| Development | - | - | - | 367 | - | 312 | - | - | 679 |
| | $ - | - | - | 382 | - | 333 | - | - | 715 |
| 2015 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Unproved property acquisition | $ - | 168 | 168 | 52 | - | - | - | - | 220 |
| Proved property acquisition | - | 5 | 5 | 1 | - | - | - | - | 6 |
| | - | 173 | 173 | 53 | - | - | - | - | 226 |
| Exploration | 87 | 1,369 | 1,456 | 298 | 107 | 118 | 394 | 47 | 2,420 |
| Development | 1,217 | 2,875 | 4,092 | 827 | 1,742 | 587 | 4 | - | 7,252 |
| | $ 1,304 | 4,417 | 5,721 | 1,178 | 1,849 | 705 | 398 | 47 | 9,898 |
| *Equity affiliates* | | | | | | | | | |
| Unproved property acquisition | $ - | - | - | - | - | - | - | - | - |
| Proved property acquisition | - | - | - | - | - | - | - | - | - |
| | - | - | - | - | - | - | - | - | - |
| Exploration | - | - | - | 17 | - | 60 | - | - | 77 |
| Development | - | - | - | 847 | - | 655 | - | 3 | 1,505 |
| | $ - | - | - | 864 | - | 715 | - | 3 | 1,582 |
| 2014 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Unproved property acquisition | $ - | 159 | 159 | 61 | 90 | - | 6 | - | 316 |
| Proved property acquisition | - | 10 | 10 | - | - | - | - | - | 10 |
| | - | 169 | 169 | 61 | 90 | - | 6 | - | 326 |
| Exploration | 130 | 1,347 | 1,477 | 332 | 243 | 166 | 556 | 58 | 2,832 |
| Development | 1,263 | 4,881 | 6,144 | 2,185 | 3,618 | 1,353 | 71 | - | 13,371 |
| | $ 1,393 | 6,397 | 7,790 | 2,578 | 3,951 | 1,519 | 633 | 58 | 16,529 |
| *Equity affiliates* | | | | | | | | | |
| Unproved property acquisition | $ - | - | - | - | - | 2 | - | - | 2 |
| Proved property acquisition | - | - | - | - | - | - | - | - | - |
| | - | - | - | - | - | 2 | - | - | 2 |
| Exploration | - | - | - | 23 | 36 | 117 | - | - | 176 |
| Development | - | - | - | 1,627 | - | 1,965 | - | 9 | 3,601 |
| | $ - | - | - | 1,650 | 36 | 2,084 | - | 9 | 3,779 |

**Certain amounts in Asia Pacific/Middle East equity affiliates have been restated in 2015 and 2014 to remove amounts considered to be non-oil and gas producing activities.*

## Capitalized Costs

| At December 31 | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East* | Africa | Other Areas | Total |
| **2016** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Proved property | $ 17,376 | 46,050 | 63,426 | 16,970 | 24,858 | 13,837 | 879 | - | 119,970 |
| Unproved property | 1,099 | 1,376 | 2,475 | 1,435 | 269 | 787 | 123 | 61 | 5,150 |
| | 18,475 | 47,426 | 65,901 | 18,405 | 25,127 | 14,624 | 1,002 | 61 | 125,120 |
| Accumulated depreciation, depletion and amortization | 8,548 | 26,858 | 35,406 | 10,344 | 15,754 | 7,635 | 297 | 1 | 69,437 |
| | $ 9,927 | 20,568 | 30,495 | 8,061 | 9,373 | 6,989 | 705 | 60 | 55,683 |
| *Equity affiliates* | | | | | | | | | |
| Proved property | $ - | - | - | 9,459 | - | 8,501 | - | - | 17,960 |
| Unproved property | - | - | - | 891 | - | 2,756 | - | - | 3,647 |
| | - | - | - | 10,350 | - | 11,257 | - | - | 21,607 |
| Accumulated depreciation, depletion and amortization | - | - | - | 1,906 | - | 1,369 | - | - | 3,275 |
| | $ - | - | - | 8,444 | - | 9,888 | - | - | 18,332 |
| 2015 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Proved property | $ 17,007 | 45,256 | 62,263 | 16,552 | 26,851 | 16,254 | 873 | 3 | 122,796 |
| Unproved property | 1,609 | 2,414 | 4,023 | 1,418 | 330 | 781 | 823 | 35 | 7,410 |
| | 18,616 | 47,670 | 66,286 | 17,970 | 27,181 | 17,035 | 1,696 | 38 | 130,206 |
| Accumulated depreciation, depletion and amortization | 8,688 | 22,993 | 31,681 | 9,371 | 16,166 | 8,853 | 788 | 4 | 66,863 |
| | $ 9,928 | 24,677 | 34,605 | 8,599 | 11,015 | 8,182 | 908 | 34 | 63,343 |
| *Equity affiliates* | | | | | | | | | |
| Proved property | $ - | - | - | 8,763 | - | 8,086 | - | - | 16,849 |
| Unproved property | - | - | - | 906 | - | 3,040 | - | - | 3,946 |
| | - | - | - | 9,669 | - | 11,126 | - | - | 20,795 |
| Accumulated depreciation, depletion and amortization | - | - | - | 1,537 | - | 1,017 | - | - | 2,554 |
| | $ - | - | - | 8,132 | - | 10,109 | - | - | 18,241 |

**Certain amounts in Asia Pacific/Middle East equity affiliates have been restated in 2015 to remove amounts considered to be non-oil and gas producing activities.*

## Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

In accordance with SEC and FASB requirements, amounts were computed using 12-month average prices (adjusted only for existing contractual terms) and end-of-year costs, appropriate statutory tax rates and a prescribed 10 percent discount factor. Twelve-month average prices are calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. For all years, continuation of year-end economic conditions was assumed. The calculations were based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, were not considered. The calculations also require assumptions as to the timing of future production of proved reserves and the timing and amount of future development costs, including dismantlement, and future production costs, including taxes other than income taxes.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

### Discounted Future Net Cash Flows

| | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
| **2016** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| Future cash inflows | $ 29,697 | 31,963 | 61,660 | 4,739 | 18,533 | 12,770 | 10,715 | 108,417 |
| Less: | | | | | | | | |
| Future production costs | 24,965 | 16,936 | 41,901 | 5,103 | 7,469 | 5,288 | 1,420 | 61,181 |
| Future development costs | 7,961 | 8,932 | 16,893 | 1,586 | 9,949 | 2,777 | 537 | 31,742 |
| Future income tax provisions (benefit) | - | 744 | 744 | - | (325) | 1,563 | 7,885 | 9,867 |
| Future net cash flows | (3,229) | 5,351 | 2,122 | (1,950) | 1,440 | 3,142 | 873 | 5,627 |
| 10 percent annual discount | (3,143) | 976 | (2,167) | (1,297) | (2) | 572 | 370 | (2,524) |
| Discounted future net cash flows | $ (86) | 4,375 | 4,289 | (653) | 1,442 | 2,570 | 503 | 8,151 |
| *Equity affiliates* | | | | | | | | |
| Future cash inflows | $ - | - | - | 15,139 | - | 17,829 | - | 32,968 |
| Less: | | | | | | | | |
| Future production costs | - | - | - | 8,514 | - | 10,620 | - | 19,134 |
| Future development costs | - | - | - | 4,993 | - | 980 | - | 5,973 |
| Future income tax provisions | - | - | - | 164 | - | 1,309 | - | 1,473 |
| Future net cash flows | - | - | - | 1,468 | - | 4,920 | - | 6,388 |
| 10 percent annual discount | - | - | - | 540 | - | 1,911 | - | 2,451 |
| Discounted future net cash flows | $ - | - | - | 928 | - | 3,009 | - | 3,937 |
| *Total company* | | | | | | | | |
| Discounted future net cash flows | $ (86) | 4,375 | 4,289 | 275 | 1,442 | 5,579 | 503 | 12,088 |

| | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
| 2015 | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| Future cash inflows | $ 44,054 | 42,575 | 86,629 | 22,317 | 27,782 | 19,368 | 13,875 | 169,971 |
| Less: | | | | | | | | |
| Future production costs | 32,732 | 21,638 | 54,370 | 13,103 | 10,574 | 7,529 | 1,422 | 86,998 |
| Future development costs | 9,885 | 12,967 | 22,852 | 6,471 | 12,793 | 2,884 | 437 | 45,437 |
| Future income tax provisions | - | 844 | 844 | - | 1,506 | 2,708 | 10,998 | 16,056 |
| Future net cash flows | 1,437 | 7,126 | 8,563 | 2,743 | 2,909 | 6,247 | 1,018 | 21,480 |
| 10 percent annual discount | (502) | 1,573 | 1,071 | 1,265 | 733 | 1,349 | 500 | 4,918 |
| Discounted future net cash flows | $ 1,939 | 5,553 | 7,492 | 1,478 | 2,176 | 4,898 | 518 | 16,562 |
| *Equity affiliates* | | | | | | | | |
| Future cash inflows | $ - | - | - | 36,211 | - | 34,257 | - | 70,468 |
| Less: | | | | | | | | |
| Future production costs | - | - | - | 16,417 | - | 17,874 | - | 34,291 |
| Future development costs | - | - | - | 11,869 | - | 2,391 | - | 14,260 |
| Future income tax provisions | - | - | - | 1,648 | - | 3,117 | - | 4,765 |
| Future net cash flows | - | - | - | 6,277 | - | 10,875 | - | 17,152 |
| 10 percent annual discount | - | - | - | 3,827 | - | 4,298 | - | 8,125 |
| Discounted future net cash flows | $ - | - | - | 2,450 | - | 6,577 | - | 9,027 |
| *Total company* | | | | | | | | |
| Discounted future net cash flows | $ 1,939 | 5,553 | 7,492 | 3,928 | 2,176 | 11,475 | 518 | 25,589 |

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| 2014 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Future cash inflows | $ 106,506 | 100,322 | 206,828 | 50,209 | 55,878 | 39,492 | 25,997 | - | 378,404 |
| Less: | | | | | | | | | |
| Future production costs | 57,924 | 37,872 | 95,796 | 21,342 | 16,372 | 12,555 | 1,338 | - | 147,403 |
| Future development costs | 10,815 | 19,666 | 30,481 | 10,400 | 14,194 | 2,985 | 437 | - | 58,497 |
| Future income tax provisions | 12,483 | 14,800 | 27,283 | 3,159 | 15,757 | 7,728 | 22,526 | - | 76,453 |
| Future net cash flows | 25,284 | 27,984 | 53,268 | 15,308 | 9,555 | 16,224 | 1,696 | - | 96,051 |
| 10 percent annual discount | 12,499 | 10,150 | 22,649 | 8,915 | 2,741 | 4,607 | 791 | - | 39,703 |
| Discounted future net cash flows | $ 12,785 | 17,834 | 30,619 | 6,393 | 6,814 | 11,617 | 905 | - | 56,348 |
| | | | | | | | | | |
| *Equity affiliates* | | | | | | | | | |
| Future cash inflows | $ - | - | - | 88,716 | - | 61,480 | - | 357 | 150,553 |
| Less: | | | | | | | | | |
| Future production costs | - | - | - | 25,455 | - | 27,274 | - | 276 | 53,005 |
| Future development costs | - | - | - | 11,595 | - | 3,007 | - | 16 | 14,618 |
| Future income tax provisions | - | - | - | 12,322 | - | 7,225 | - | 10 | 19,557 |
| Future net cash flows | - | - | - | 39,344 | - | 23,974 | - | 55 | 63,373 |
| 10 percent annual discount | - | - | - | 25,601 | - | 10,897 | - | 6 | 36,504 |
| Discounted future net cash flows | $ - | - | - | 13,743 | - | 13,077 | - | 49 | 26,869 |
| | | | | | | | | | |
| *Total company* | | | | | | | | | |
| Discounted future net cash flows | $ 12,785 | 17,834 | 30,619 | 20,136 | 6,814 | 24,694 | 905 | 49 | 83,217 |

## Sources of Change in Discounted Future Net Cash Flows

| | Millions of Dollars | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Consolidated Operations | | | Equity Affiliates | | | Total Company | | | |
| | | **2016** | 2015 | 2014 | **2016** | 2015* | 2014* | **2016** | 2015* | 2014* |
| Discounted future net cash flows at the beginning of the year | $ | **16,562** | 56,348 | 56,003 | **9,027** | 26,869 | 21,509 | **25,589** | 83,217 | 77,512 |
| Changes during the year | | | | | | | | | | |
| Revenues less production costs for the year | | **(6,313)** | (8,158) | (19,571) | **(956)** | (966) | (2,748) | **(7,269)** | (9,124) | (22,319) |
| Net change in prices and production costs | | **(16,476)** | (82,923) | (9,243) | **(9,317)** | (27,670) | 4,517 | **(25,793)** | (110,593) | (4,726) |
| Extensions, discoveries and improved recovery, less estimated future costs | | **1,358** | 1,791 | 7,033 | **(77)** | 319 | 1,822 | **1,281** | 2,110 | 8,855 |
| Development costs for the year | | **3,118** | 6,854 | 11,785 | **722** | 1,493 | 3,453 | **3,840** | 8,347 | 15,238 |
| Changes in estimated future development costs | | **6,646** | 2,073 | (7,771) | **2,435** | (227) | (1,613) | **9,081** | 1,846 | (9,384) |
| Purchases of reserves in place, less estimated future costs | | **2** | - | - | **-** | - | 5 | **2** | - | 5 |
| Sales of reserves in place, less estimated future costs | | **(123)** | (424) | (1,280) | **-** | (38) | - | **(123)** | (462) | (1,280) |
| Revisions of previous quantity estimates | | **(3,252)** | (1,790) | 1,348 | **(436)** | 938 | (1,166) | **(3,688)** | (852) | 182 |
| Accretion of discount | | **2,540** | 9,342 | 10,045 | **1,058** | 3,297 | 2,648 | **3,598** | 12,639 | 12,693 |
| Net change in income taxes | | **4,089** | 33,449 | 7,999 | **1,481** | 5,012 | (1,558) | **5,570** | 38,461 | 6,441 |
| Total changes | | **(8,411)** | (39,786) | 345 | **(5,090)** | (17,842) | 5,360 | **(13,501)** | (57,628) | 5,705 |
| Discounted future net cash flows at year end | $ | **8,151** | 16,562 | 56,348 | **3,937** | 9,027 | 26,869 | **12,088** | 25,589 | 83,217 |

**Certain amounts in equity affiliates were restated to reclassify amounts between "Development costs for the year" and "Changes in estimated future development costs."*

- The net change in prices and production costs is the beginning-of-year reserve-production forecast multiplied by the net annual change in the per-unit sales price and production cost, discounted at 10 percent.

- Purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.

- Revisions of previous quantity estimates are calculated using production forecast changes for the year, including changes in the timing of production, multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.

- The accretion of discount is 10 percent of the prior year's discounted future cash inflows, less future production and development costs.

- The net change in income taxes is the annual change in the discounted future income tax provisions.

**Selected Quarterly Financial Data** (Unaudited)

| | Millions of Dollars | | | | Per Share of Common Stock | |
|---|---|---|---|---|---|---|
| | Sales and Other Operating Revenues | Income (Loss) From Continuing Operations Before Income Taxes | Net Income (Loss) | Net Income (Loss) Attributable to ConocoPhillips | Net Income (Loss) Attributable to ConocoPhillips Basic | Net Income (Loss) Attributable to ConocoPhillips Diluted |
| **2016** | | | | | | |
| First | **$ 5,121** | **(2,224)** | **(1,456)** | **(1,469)** | **(1.18)** | **(1.18)** |
| Second | **5,348** | **(1,644)** | **(1,058)** | **(1,071)** | **(0.86)** | **(0.86)** |
| Third | **6,415** | **(1,654)** | **(1,026)** | **(1,040)** | **(0.84)** | **(0.84)** |
| Fourth | **6,809** | **(8)** | **(19)** | **(35)** | **(0.03)** | **(0.03)** |
| 2015 | | | | | | |
| First | $ 7,716 | (356) | 286 | 272 | 0.22 | 0.22 |
| Second | 8,293 | (91) | (164) | (179) | (0.15) | (0.15) |
| Third | 7,262 | (1,741) | (1,056) | (1,071) | (0.87) | (0.87) |
| Fourth | 6,293 | (5,051) | (3,437) | (3,450) | (2.78) | (2.78) |

*For additional information on the commodity price environment, see the Business Environment and Executive Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations.*

**Supplementary Information—Condensed Consolidating Financial Information**

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company and ConocoPhillips Canada Funding Company I, with respect to publicly held debt securities. ConocoPhillips Company is 100 percent owned by ConocoPhillips. ConocoPhillips Canada Funding Company I is an indirect, 100 percent owned subsidiary of ConocoPhillips Company. ConocoPhillips and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Canada Funding Company I, with respect to their publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial information presents the results of operations, financial position and cash flows for:

- ConocoPhillips, ConocoPhillips Company and ConocoPhillips Canada Funding Company I (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).
- All other nonguarantor subsidiaries of ConocoPhillips.
- The consolidating adjustments necessary to present ConocoPhillips' results on a consolidated basis.

In May 2014, we filed a universal shelf registration statement with the SEC under which ConocoPhillips, as a well-known seasoned issuer, has the ability to issue and sell an indeterminate amount of various types of debt and equity securities, with certain debt securities guaranteed by ConocoPhillips Company. Also as part of that registration statement, ConocoPhillips Trust I and ConocoPhillips Trust II have the ability to issue and sell preferred trust securities, guaranteed by ConocoPhillips. ConocoPhillips Trust I and ConocoPhillips Trust II have not issued any trust-preferred securities under this registration statement, and thus have no assets or liabilities. Accordingly, columns for these two trusts are not included in the condensed consolidating financial information.

In 2014, ConocoPhillips received $34.5 billion in dividends from ConocoPhillips Company to settle certain accumulated intercompany balances. This consisted of a $17.5 billion distribution of earnings and a $17 billion return of capital. These transactions had no impact on our consolidated financial statements.

In 2015, ConocoPhillips received a $3.5 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2016, ConocoPhillips received a $2.3 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2016, ConocoPhillips Canada Funding Company I repaid $1.25 billion of external debt. This transaction is reflected in our consolidated financial statements.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes.

| Income Statement | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
|---|---|---|---|---|---|---|
| | Millions of Dollars | | | | | |
| | Year Ended December 31, 2016 | | | | | |
| **Revenues and Other Income** | | | | | | |
| Sales and other operating revenues | $ - | 10,352 | - | 13,341 | - | 23,693 |
| Equity in earnings (losses) of affiliates | (3,351) | (1,051) | - | (91) | 4,545 | 52 |
| Gain on dispositions | - | 120 | - | 240 | - | 360 |
| Other income (loss) | 1 | (11) | - | 265 | - | 255 |
| Intercompany revenues | 88 | 277 | 220 | 3,036 | (3,621) | - |
| Total Revenues and Other Income | (3,262) | 9,687 | 220 | 16,791 | 924 | 24,360 |
| **Costs and Expenses** | | | | | | |
| Purchased commodities | - | 9,144 | - | 3,562 | (2,712) | 9,994 |
| Production and operating expenses | - | 779 | - | 5,131 | (243) | 5,667 |
| Selling, general and administrative expenses | 8 | 581 | - | 140 | (6) | 723 |
| Exploration expenses | - | 1,231 | - | 684 | - | 1,915 |
| Depreciation, depletion and amortization | - | 1,178 | - | 7,884 | - | 9,062 |
| Impairments | - | 67 | - | 72 | - | 139 |
| Taxes other than income taxes | - | 162 | - | 577 | - | 739 |
| Accretion on discounted liabilities | - | 46 | - | 379 | - | 425 |
| Interest and debt expense | 506 | 622 | 207 | 570 | (660) | 1,245 |
| Foreign currency transaction (gains) losses | (19) | 2 | 174 | (176) | - | (19) |
| Total Costs and Expenses | 495 | 13,812 | 381 | 18,823 | (3,621) | 29,890 |
| Loss from continuing operations before income taxes | (3,757) | (4,125) | (161) | (2,032) | 4,545 | (5,530) |
| Income tax benefit | (142) | (774) | (9) | (1,046) | - | (1,971) |
| Net loss | (3,615) | (3,351) | (152) | (986) | 4,545 | (3,559) |
| Less: net income attributable to noncontrolling interests | - | - | - | (56) | - | (56) |
| **Loss Attributable to ConocoPhillips** | $ (3,615) | (3,351) | (152) | (1,042) | 4,545 | (3,615) |
| **Comprehensive Loss Attributable to ConocoPhillips** | $ (3,561) | (3,297) | (27) | (952) | 4,276 | (3,561) |
| **Income Statement** | Year Ended December 31, 2015 | | | | | |
| **Revenues and Other Income** | | | | | | |
| Sales and other operating revenues | $ - | 11,473 | - | 18,091 | - | 29,564 |
| Equity in earnings (losses) of affiliates | (4,081) | (1,950) | - | 1,364 | 5,322 | 655 |
| Gain on dispositions | - | 332 | - | 259 | - | 591 |
| Other income | - | 12 | - | 113 | - | 125 |
| Intercompany revenues | 74 | 341 | 246 | 3,365 | (4,026) | - |
| Total Revenues and Other Income | (4,007) | 10,208 | 246 | 23,192 | 1,296 | 30,935 |
| **Costs and Expenses** | | | | | | |
| Purchased commodities | - | 9,905 | - | 5,838 | (3,317) | 12,426 |
| Production and operating expenses | - | 1,469 | - | 5,585 | (38) | 7,016 |
| Selling, general and administrative expenses | 9 | 744 | 1 | 209 | (10) | 953 |
| Exploration expenses | - | 2,093 | - | 2,099 | - | 4,192 |
| Depreciation, depletion and amortization | - | 1,201 | - | 7,912 | - | 9,113 |
| Impairments | - | 15 | - | 2,230 | - | 2,245 |
| Taxes other than income taxes | - | 173 | - | 728 | - | 901 |
| Accretion on discounted liabilities | - | 58 | - | 425 | - | 483 |
| Interest and debt expense | 485 | 423 | 226 | 447 | (661) | 920 |
| Foreign currency transaction (gains) losses | 114 | 1 | (708) | 518 | - | (75) |
| Total Costs and Expenses | 608 | 16,082 | (481) | 25,991 | (4,026) | 38,174 |
| Income (loss) from continuing operations before income taxes | (4,615) | (5,874) | 727 | (2,799) | 5,322 | (7,239) |
| Income tax provision (benefit) | (187) | (1,793) | 21 | (909) | - | (2,868) |
| Net income (loss) | (4,428) | (4,081) | 706 | (1,890) | 5,322 | (4,371) |
| Less: net income attributable to noncontrolling interests | - | - | - | (57) | - | (57) |
| **Net Income (Loss) Attributable to ConocoPhillips** | $ (4,428) | (4,081) | 706 | (1,947) | 5,322 | (4,428) |
| **Comprehensive Income (Loss) Attributable to ConocoPhillips** | $ (8,773) | (8,426) | 71 | (6,705) | 15,060 | (8,773) |

| Income Statement | | | | | | |
|---|---|---|---|---|---|---|
| | Millions of Dollars | | | | | |
| | Year Ended December 31, 2014 | | | | | |
| | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
| **Revenues and Other Income** | | | | | | |
| Sales and other operating revenues | $ - | 20,083 | - | 32,441 | - | 52,524 |
| Equity in earnings of affiliates | 6,108 | 8,090 | - | 2,932 | (14,601) | 2,529 |
| Gain on dispositions | - | 9 | - | 89 | - | 98 |
| Other income (loss) | (6) | 67 | - | 305 | - | 366 |
| Intercompany revenues | 79 | 465 | 283 | 5,883 | (6,710) | - |
| Total Revenues and Other Income | 6,181 | 28,714 | 283 | 41,650 | (21,311) | 55,517 |
| **Costs and Expenses** | | | | | | |
| Purchased commodities | - | 17,591 | - | 10,415 | (5,907) | 22,099 |
| Production and operating expenses | - | 2,600 | - | 6,368 | (59) | 8,909 |
| Selling, general and administrative expenses | 9 | 575 | 1 | 166 | (16) | 735 |
| Exploration expenses | - | 1,036 | - | 1,009 | - | 2,045 |
| Depreciation, depletion and amortization | - | 1,059 | - | 7,270 | - | 8,329 |
| Impairments | - | 127 | - | 729 | - | 856 |
| Taxes other than income taxes | - | 285 | - | 1,803 | - | 2,088 |
| Accretion on discounted liabilities | - | 58 | - | 426 | - | 484 |
| Interest and debt expense | 571 | 299 | 231 | 275 | (728) | 648 |
| Foreign currency transaction (gains) losses | 62 | 10 | (372) | 234 | - | (66) |
| Total Costs and Expenses | 642 | 23,640 | (140) | 28,695 | (6,710) | 46,127 |
| Income from continuing operations before income taxes | 5,539 | 5,074 | 423 | 12,955 | (14,601) | 9,390 |
| Income tax provision (benefit) | (199) | (1,034) | 19 | 4,797 | - | 3,583 |
| **Income From Continuing Operations** | 5,738 | 6,108 | 404 | 8,158 | (14,601) | 5,807 |
| Income from discontinued operations | 1,131 | 1,131 | - | 113 | (1,244) | 1,131 |
| Net income | 6,869 | 7,239 | 404 | 8,271 | (15,845) | 6,938 |
| Less: net income attributable to noncontrolling interests | - | - | - | (69) | - | (69) |
| **Net Income Attributable to ConocoPhillips** | $ 6,869 | 7,239 | 404 | 8,202 | (15,845) | 6,869 |
| **Comprehensive Income Attributable to ConocoPhillips** | $ 2,965 | 3,335 | 58 | 4,589 | (7,982) | 2,965 |

| Balance Sheet | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
|---|---|---|---|---|---|---|
| | Millions of Dollars | | | | | |
| | At December 31, 2016 | | | | | |
| **Assets** | | | | | | |
| Cash and cash equivalents | $ - | 358 | 13 | 3,239 | - | 3,610 |
| Short-term investments | - | - | - | 50 | - | 50 |
| Accounts and notes receivable | 22 | 1,968 | 23 | 6,103 | (4,702) | 3,414 |
| Inventories | - | 84 | - | 934 | - | 1,018 |
| Prepaid expenses and other current assets | 2 | 116 | 8 | 415 | (24) | 517 |
| Total Current Assets | 24 | 2,526 | 44 | 10,741 | (4,726) | 8,609 |
| Investments, loans and long-term receivables* | 37,901 | 64,434 | 2,296 | 31,643 | (114,602) | 21,672 |
| Net properties, plants and equipment | - | 6,301 | - | 52,030 | - | 58,331 |
| Other assets | 40 | 2,194 | 220 | 1,240 | (2,534) | 1,160 |
| Total Assets | $ 37,965 | 75,455 | 2,560 | 95,654 | (121,862) | 89,772 |
| **Liabilities and Stockholders' Equity** | | | | | | |
| Accounts payable | $ - | 4,683 | 1 | 3,671 | (4,702) | 3,653 |
| Short-term debt | (10) | 999 | 6 | 94 | - | 1,089 |
| Accrued income and other taxes | - | 85 | - | 399 | - | 484 |
| Employee benefit obligations | - | 489 | - | 200 | - | 689 |
| Other accruals | 171 | 271 | 40 | 536 | (24) | 994 |
| Total Current Liabilities | 161 | 6,527 | 47 | 4,900 | (4,726) | 6,909 |
| Long-term debt | 8,975 | 12,635 | 1,710 | 2,866 | - | 26,186 |
| Asset retirement obligations and accrued environmental costs | - | 925 | - | 7,500 | - | 8,425 |
| Deferred income taxes | - | - | - | 10,972 | (2,023) | 8,949 |
| Employee benefit obligations | - | 1,901 | - | 651 | - | 2,552 |
| Other liabilities and deferred credits* | 417 | 10,391 | 748 | 17,832 | (27,863) | 1,525 |
| Total Liabilities | 9,553 | 32,379 | 2,505 | 44,721 | (34,612) | 54,546 |
| Retained earnings | 25,025 | 14,015 | (541) | 12,883 | (19,834) | 31,548 |
| Other common stockholders' equity | 3,387 | 29,061 | 596 | 37,798 | (67,416) | 3,426 |
| Noncontrolling interests | - | - | - | 252 | - | 252 |
| Total Liabilities and Stockholders' Equity | $ 37,965 | 75,455 | 2,560 | 95,654 | (121,862) | 89,772 |

| Balance Sheet | | | | | | |
|---|---|---|---|---|---|---|
| | At December 31, 2015 | | | | | |
| **Assets** | | | | | | |
| Cash and cash equivalents | $ - | 4 | 15 | 2,349 | - | 2,368 |
| Accounts and notes receivable | 21 | 2,905 | 21 | 7,228 | (5,661) | 4,514 |
| Inventories | - | 142 | - | 982 | - | 1,124 |
| Prepaid expenses and other current assets | 2 | 206 | 252 | 589 | (266) | 783 |
| Total Current Assets | 23 | 3,257 | 288 | 11,148 | (5,927) | 8,789 |
| Investments, loans and long-term receivables* | 43,532 | 64,015 | 3,264 | 27,839 | (117,464) | 21,186 |
| Net properties, plants and equipment | - | 8,110 | - | 58,336 | - | 66,446 |
| Other assets | 7 | 950 | 233 | 1,158 | (1,285) | 1,063 |
| Total Assets | $ 43,562 | 76,332 | 3,785 | 98,481 | (124,676) | 97,484 |
| **Liabilities and Stockholders' Equity** | | | | | | |
| Accounts payable | $ - | 5,684 | 13 | 4,897 | (5,661) | 4,933 |
| Short-term debt | (9) | 1 | 1,255 | 180 | - | 1,427 |
| Accrued income and other taxes | - | 62 | - | 437 | - | 499 |
| Employee benefit obligations | - | 629 | - | 258 | - | 887 |
| Other accruals | 170 | 465 | 52 | 1,087 | (264) | 1,510 |
| Total Current Liabilities | 161 | 6,841 | 1,320 | 6,859 | (5,925) | 9,256 |
| Long-term debt | 7,518 | 10,660 | 1,716 | 3,559 | - | 23,453 |
| Asset retirement obligations and accrued environmental costs | - | 1,107 | - | 8,473 | - | 9,580 |
| Deferred income taxes | - | - | - | 11,814 | (815) | 10,999 |
| Employee benefit obligations | - | 1,760 | - | 526 | - | 2,286 |
| Other liabilities and deferred credits* | 2,681 | 7,291 | 667 | 15,181 | (23,992) | 1,828 |
| Total Liabilities | 10,360 | 27,659 | 3,703 | 46,412 | (30,732) | 57,402 |
| Retained earnings | 29,892 | 17,366 | (389) | 15,177 | (25,632) | 36,414 |
| Other common stockholders' equity | 3,310 | 31,307 | 471 | 36,572 | (68,312) | 3,348 |
| Noncontrolling interests | - | - | - | 320 | - | 320 |
| Total Liabilities and Stockholders' Equity | $ 43,562 | 76,332 | 3,785 | 98,481 | (124,676) | 97,484 |

**Includes intercompany loans.*

| Statement of Cash Flows | | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|---|
| | | Year Ended December 31, 2016 | | | | | |
| | | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
| **Cash Flows From Operating Activities** | | | | | | | |
| Net Cash Provided by (Used in) Operating Activities | $ | (306) | (322) | (2) | 5,903 | (870) | 4,403 |
| **Cash Flows From Investing Activities** | | | | | | | |
| Capital expenditures and investments | | - | (989) | - | (4,281) | 401 | (4,869) |
| Working capital changes associated with investing activities | | - | (126) | - | (205) | - | (331) |
| Proceeds from asset dispositions | | 2,300 | 266 | - | 1,114 | (2,394) | 1,286 |
| Net sales of short-term investments | | - | - | - | (51) | - | (51) |
| Long-term advances/loans—related parties | | - | (812) | - | - | 812 | - |
| Collection of advances/loans—related parties | | - | 391 | 1,250 | 272 | (1,805) | 108 |
| Intercompany cash management | | (2,214) | 1,433 | - | 781 | - | - |
| Other | | - | 1 | - | (3) | - | (2) |
| Net Cash Provided by (Used in) Investing Activities | | 86 | 164 | 1,250 | (2,373) | (2,986) | (3,859) |
| **Cash Flows From Financing Activities** | | | | | | | |
| Issuance of debt | | 1,600 | 2,994 | - | 812 | (812) | 4,594 |
| Repayment of debt | | (150) | (164) | (1,250) | (2,492) | 1,805 | (2,251) |
| Issuance of company common stock | | 148 | - | - | - | (211) | (63) |
| Repurchase of company common stock | | (126) | - | - | - | - | (126) |
| Dividends paid | | (1,253) | - | - | (1,081) | 1,081 | (1,253) |
| Other | | 1 | (2,315) | - | 184 | 1,993 | (137) |
| Net Cash Provided by (Used in) Financing Activities | | 220 | 515 | (1,250) | (2,577) | 3,856 | 764 |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | | - | (3) | - | (63) | - | (66) |
| **Net Change in Cash and Cash Equivalents** | | - | 354 | (2) | 890 | - | 1,242 |
| Cash and cash equivalents at beginning of period | | - | 4 | 15 | 2,349 | - | 2,368 |
| Cash and Cash Equivalents at End of Period | $ | - | 358 | 13 | 3,239 | - | 3,610 |

| Statement of Cash Flows | | Year Ended December 31, 2015 | | | | | |
|---|---|---|---|---|---|---|---|
| **Cash Flows From Operating Activities** | | | | | | | |
| Net Cash Provided by (Used in) Operating Activities | | (225) | 245 | 9 | 7,519 | 24 | 7,572 |
| **Cash Flows From Investing Activities** | | | | | | | |
| Capital expenditures and investments | | - | (3,064) | - | (8,386) | 1,400 | (10,050) |
| Working capital changes associated with investing activities | | - | (4) | - | (964) | - | (968) |
| Proceeds from asset dispositions | | 3,500 | 826 | - | 1,225 | (3,599) | 1,952 |
| Long-term advances/loans—related parties | | - | (278) | - | (2,245) | 2,523 | - |
| Collection of advances/loans—related parties | | - | - | - | 205 | (100) | 105 |
| Intercompany cash management | | 102 | 46 | - | (148) | - | - |
| Other | | - | 304 | - | 1 | 1 | 306 |
| Net Cash Provided by (Used in) Investing Activities | | 3,602 | (2,170) | - | (10,312) | 225 | (8,655) |
| **Cash Flows From Financing Activities** | | | | | | | |
| Issuance of debt | | - | 4,743 | - | 278 | (2,523) | 2,498 |
| Repayment of debt | | - | (100) | - | (103) | 100 | (103) |
| Issuance of company common stock | | 283 | - | - | (2) | (363) | (82) |
| Dividends paid | | (3,664) | - | - | (339) | 339 | (3,664) |
| Other | | 4 | (3,484) | - | 1,204 | 2,198 | (78) |
| Net Cash Provided by (Used in) Financing Activities | | (3,377) | 1,159 | - | 1,038 | (249) | (1,429) |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | | - | - | (1) | (181) | - | (182) |
| **Net Change in Cash and Cash Equivalents** | | - | (766) | 8 | (1,936) | - | (2,694) |
| Cash and cash equivalents at beginning of period | | - | 770 | 7 | 4,285 | - | 5,062 |
| Cash and Cash Equivalents at End of Period | $ | - | 4 | 15 | 2,349 | - | 2,368 |

| Statement of Cash Flows | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, 2014 | | | | | |
| | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
| **Cash Flows From Operating Activities** | | | | | | |
| Net cash provided by (used in) continuing operating activities | $ 17,259 | 2,948 | 27 | 16,941 | (20,763) | 16,412 |
| Net cash provided by discontinued operations | - | 202 | - | 408 | (453) | 157 |
| Net Cash Provided by (Used in) Operating Activities | 17,259 | 3,150 | 27 | 17,349 | (21,216) | 16,569 |
| **Cash Flows From Investing Activities** | | | | | | |
| Capital expenditures and investments | - | (6,507) | - | (14,840) | 4,262 | (17,085) |
| Working capital changes associated with investing activities | - | 17 | - | 163 | - | 180 |
| Proceeds from asset dispositions | 16,912 | 1,588 | - | 253 | (17,150) | 1,603 |
| Net purchases of short-term investments | - | - | - | 253 | - | 253 |
| Long-term advances/loans—related parties | - | (736) | (241) | (7) | 984 | - |
| Collection of advances/loans—related parties | - | 593 | - | 112 | (102) | 603 |
| Intercompany cash management | (29,113) | 31,993 | - | (2,880) | - | - |
| Other | - | (415) | - | (31) | - | (446) |
| Net cash provided by (used in) continuing investing activities | (12,201) | 26,533 | (241) | (16,977) | (12,006) | (14,892) |
| Net cash provided by (used in) discontinued operations | - | 133 | - | (73) | (133) | (73) |
| Net Cash Provided by (Used in) Investing Activities | (12,201) | 26,666 | (241) | (17,050) | (12,139) | (14,965) |
| **Cash Flows From Financing Activities** | | | | | | |
| Issuance of debt | - | 2,994 | - | 984 | (984) | 2,994 |
| Repayment of debt | (1,909) | (16) | - | (191) | 102 | (2,014) |
| Issuance of company common stock | 377 | - | - | - | (342) | 35 |
| Dividends paid | (3,525) | (17,588) | - | (3,768) | 21,356 | (3,525) |
| Other | (1) | (16,870) | - | 3,919 | 12,888 | (64) |
| Net cash used in continuing financing activities | (5,058) | (31,480) | - | 944 | 33,020 | (2,574) |
| Net cash used in discontinued operations | - | - | - | (335) | 335 | - |
| Net Cash Used in Financing Activities | (5,058) | (31,480) | - | 609 | 33,355 | (2,574) |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | - | - | (8) | (206) | - | (214) |
| **Net Change in Cash and Cash Equivalents** | - | (1,664) | (222) | 702 | - | (1,184) |
| Cash and cash equivalents at beginning of period | - | 2,434 | 229 | 3,583 | - | 6,246 |
| Cash and Cash Equivalents at End of Period | $ - | 770 | 7 | 4,285 | - | 5,062 |

## Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## Item 9A. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures designed to ensure information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the Act), is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of December 31, 2016, with the participation of our management, our Chairman and Chief Executive Officer (principal executive officer) and our Executive Vice President, Finance, Commercial and Chief Financial Officer (principal financial officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Act, of ConocoPhillips' disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman and Chief Executive Officer and our Executive Vice President, Finance, Commercial and Chief Financial Officer concluded our disclosure controls and procedures were operating effectively as of December 31, 2016.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

### Management's Annual Report on Internal Control Over Financial Reporting

This report is included in Item 8 on page 78 and is incorporated herein by reference.

### Report of Independent Registered Public Accounting Firm

This report is included in Item 8 on page 80 and is incorporated herein by reference.

## Item 9B. OTHER INFORMATION

None.

## PART III

### Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our executive officers appears in Part I of this report on pages 29 and 30.

**Code of Business Ethics and Conduct for Directors and Employees**

We have a Code of Business Ethics and Conduct for Directors and Employees (Code of Ethics), including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have posted a copy of our Code of Ethics on the "Corporate Governance" section of our internet website at *www.conocophillips.com* (within the Investors>Corporate Governance section). Any waivers of the Code of Ethics must be approved, in advance, by our full Board of Directors. Any amendments to, or waivers from, the Code of Ethics that apply to our executive officers and directors will be posted on the "Corporate Governance" section of our internet website.

All other information required by Item 10 of Part III will be included in our Proxy Statement relating to our 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2017, and is incorporated herein by reference.*

### Item 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2017, and is incorporated herein by reference.*

### Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2017, and is incorporated herein by reference.*

### Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2017, and is incorporated herein by reference.*

### Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2017, and is incorporated herein by reference.*

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**Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in our 2017 Proxy Statement are not deemed to be a part of this Annual Report on Form 10-K or deemed to be filed with the Commission as a part of this report.*

## PART IV

### Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements and Supplementary Data
The financial statements and supplementary information listed in the Index to Financial Statements, which appears on page 77, are filed as part of this annual report.

2. Financial Statement Schedules
Schedule II—Valuation and Qualifying Accounts, appears below. All other schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to consolidated financial statements.

3. Exhibits
The exhibits listed in the Index to Exhibits, which appears on pages 180 through 188, are filed as part of this annual report.

### SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS (Consolidated)

**ConocoPhillips**

| | | Millions of Dollars | | | | |
|---|---|---|---|---|---|---|
| Description | | Balance at January 1 | Charged to Expense | Other(a) | Deductions | Balance at December 31 |
| **2016** | | | | | | |
| Deducted from asset accounts: | | | | | | |
| Allowance for doubtful accounts and notes receivable | **$** | **7** | **3** | **(1)** | **(4)(b)** | **5** |
| Deferred tax asset valuation allowance | | **734** | **(31)** | **(12)** | **(16)** | **675** |
| Included in other liabilities: | | | | | | |
| Restructuring accruals | | **156** | **129** | **1** | **(206)(c)** | **80** |
| 2015 | | | | | | |
| Deducted from asset accounts: | | | | | | |
| Allowance for doubtful accounts and notes receivable | $ | 5 | 4 | (2) | - (b) | 7 |
| Deferred tax asset valuation allowance | | 970 | 6 | (21) | (221) | 734 |
| Included in other liabilities: | | | | | | |
| Restructuring accruals | | 61 | 303 | (8) | (200)(c) | 156 |
| 2014 | | | | | | |
| Deducted from asset accounts: | | | | | | |
| Allowance for doubtful accounts and notes receivable | $ | 8 | - | (2) | (1)(b) | 5 |
| Deferred tax asset valuation allowance | | 969 | 127 | (26) | (100) | 970 |
| Included in other liabilities: | | | | | | |
| Restructuring accruals | | 19 | 71 | (6) | (23)(c) | 61 |

*(a)Represents acquisitions/dispositions/revisions and the effect of translating foreign financial statements.*
*(b)Amounts charged off less recoveries of amounts previously charged off.*
*(c)Benefit payments.*

## CONOCOPHILLIPS

## INDEX TO EXHIBITS

| Exhibit Number | Description |
|---|---|
| 2.1 | Separation and Distribution Agreement Between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 3.1 | Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395). |
| 3.2 | Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987). |
| 3.3 | Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of December 6, 2013 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed December 10, 2013; File No. 001-32395). |
| 3.4 | Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of October 9, 2015 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on October 13, 2015; File No. 001-32395). |
| | ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request. |
| 10.1 | 1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.2 | 1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.3 | Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.4 | Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 001-00720). |
| 10.5 | Amendment and Restatement of ConocoPhillips Supplemental Executive Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.14 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.6 | Non-Employee Director Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.18 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.7 | Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.19 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.8 | Key Employee Missed Credited Service Retirement Plan of ConocoPhillips (incorporated by reference to Exhibit 10.10 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395). |
| 10.9 | Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.10.1 | Amendment and Restatement of ConocoPhillips Key Employee Supplemental Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.13 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.10.2 | First Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan, dated July 20, 2015 (incorporated by reference to Exhibit 10.10.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.10.3 | Second Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan, dated March 14, 2016 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395). |
| 10.11.1 | Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips—Title I, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.11.2 | Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.11.3 | First Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated October 11, 2012 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395). |
| 10.11.4 | Second Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated December 17, 2015 (incorporated by reference to Exhibit 10.11.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.12 | 2002 Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.13 | Amendment and Restatement of 1998 Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |

| Exhibit Number | Description |
|---|---|
| 10.14 | Amendment and Restatement of 1998 Key Employee Stock Performance Plan of ConocoPhillips (incorporated by reference to Exhibit 10.28 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.15 | Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips (incorporated by reference to Exhibit 10.17 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395). |
| 10.16 | ConocoPhillips Form Indemnity Agreement with Directors (incorporated by reference to Exhibit 10.34 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.17.1 | Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of the Annual Report of ConocoPhillips Holding Company on Form 10-K for the year ended December 31, 1999; File No. 001-14521). |
| 10.17.2 | Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.17.3 | Phillips Petroleum Company Grantor Trust Agreement, dated June 1, 1998 (incorporated by reference to Exhibit 10.17.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.17.4 | First Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated May 3, 1999 (incorporated by reference to Exhibit 10.17.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.17.5 | Second Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated January 15, 2002 (incorporated by reference to Exhibit 10.17.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.17.6 | Third Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated October 5, 2006 (incorporated by reference to Exhibit 10.17.6 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.17.7 | Fourth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 1, 2012 (incorporated by reference to Exhibit 10.17.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.17.8 | Fifth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 20, 2015 (incorporated by reference to Exhibit 10.17.8 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.18.1 | ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10.40 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987). |
| 10.18.2 | First and Second Amendments to the ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.19 | ConocoPhillips Matching Gift Plan for Directors and Executives (incorporated by reference to Exhibit 10.41 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987). |
| 10.20.1 | Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title I, dated April 19, 2012 (incorporated by reference to Exhibit 10.12.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.20.2 | Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, dated April 19, 2012 (incorporated by reference to Exhibit 10.12.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.20.3 | First Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips—Title II (incorporated by reference to Exhibit 10.20.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395). |
| 10.20.4 | Second Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips—Title II (incorporated by reference to Exhibit 10.20.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395). |
| 10.20.5 | Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, 2013 Restatement dated November 17, 2014 (Amended and Restated effective as of January 1, 2013) (incorporated by reference to Exhibit 10.20.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2014; File No. 001-32395). |
| 10.21 | Amendment and Restatement of ConocoPhillips Key Employee Change in Control Severance Plan, effective January 1, 2014 (incorporated by reference to Exhibit 10.21 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2013; File No. 001-32395). |
| 10.22 | ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395). |
| 10.23.1 | 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix C of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2004 Annual Meeting of Shareholders; File No. 000-49987). |
| 10.23.2 | Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395). |
| 10.23.3 | Form of Performance Share Unit Award Agreement under the Performance Share Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395). |
| 10.24 | Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007 (incorporated by reference to Exhibit 10.30 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2007; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.25 | 2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2009 Annual Meeting of Shareholders; File No. 001-32395). |
| 10.26.1 | 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2011 Annual Meeting of Shareholders; File No. 001-32395). |
| 10.26.2 | Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective February 9, 2012 (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2012; File No. 001-32395). |
| 10.26.3 | Form of Restricted Stock Units Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective April 4, 2012 (incorporated by reference to Exhibit 10.6 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.26.4 | Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective May 8, 2012 (incorporated by reference to Exhibit 10.7 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.26.5 | Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 18, 2012 (incorporated by reference to Exhibit 10.26.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.6 | Form of Performance Share Unit Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.6 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.7 | Form of Performance Share Unit Agreement—Canada under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.8 | Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.8 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.9 | Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.9 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.10 | Form of Make-up Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated January 1, 2012 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2013; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.26.11 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.12 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.26.13 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Restricted Stock Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.14 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.14 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.26.15 | Form of Performance Period IX Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.16 | Form of Performance Period IX Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.4 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.17 | Form of Performance Period X Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.5 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.18 | Form of Performance Period X Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.6 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.19 | Form of Performance Period XI Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.7 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.26.20 | Form of Performance Period XI Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.8 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.21 | Form of Performance Period XII Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.22 | Form of Performance Period XII Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.23 | Form of Performance Period XIV Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.26.24 | Form of Performance Period XIV Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.24 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.26.25 | Form of Inducement Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated March 31, 2014 (incorporated by reference to Exhibit 10.11 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.27.1 | 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 14, 2014; File No. 001-32395). |
| 10.27.2 | Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program of ConocoPhillips, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 15, 2014 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2014; File No. 001-32395). |
| 10.27.3 | Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 3, 2015 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2015; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.27.4 | Form of Retention Award Terms and Conditions, as part of the Restricted Stock Unit Award, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2015; File No. 001-32395). |
| 10.27.5 | Form of Non-Employee Director Restricted Stock Units Terms and Conditions, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395). |
| 10.27.6 | Form of Non-Employee Director Restricted Stock Units Terms and Conditions – Canadian Non-Employee Directors, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.4 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395). |
| 10.27.7 | Form of Non-Employee Director Restricted Stock Units Terms and Conditions – Norwegian Non-Employee Directors, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.5 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395). |
| 10.28 | Amendment and Restatement of Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips, dated April 19, 2012 (incorporated by reference to Exhibit 10.8 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.29 | Amendment, Change of Sponsorship, and Restatement of Certain Nonqualified Deferred Compensation Plans of ConocoPhillips, dated April 19, 2012 (incorporated by reference to Exhibit 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.30 | Amendment and Restatement of the Burlington Resources Inc. Management Supplemental Benefits Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.31 | Amendment and Restatement of Deferred Compensation Trust Agreement for Non-Employee Directors of Phillips Petroleum Company, dated June 23, 1995 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395). |
| 10.32 | Indemnification and Release Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.33 | Intellectual Property Assignment and License Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.2 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.34 | Tax Sharing Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.3 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |

| Exhibit Number | Description |
| --- | --- |
| 10.35 | Employee Matters Agreement between ConocoPhillips and Phillips 66, dated April 12, 2012 (incorporated by reference to Exhibit 10.4 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.36 | Transition Services Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.5 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.37 | ConocoPhillips Clawback Policy dated October 3, 2012 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395). |
| 10.38 | Term Loan Agreement, between ConocoPhillips, as borrower, ConocoPhillips Company, as guarantor, Toronto Dominion (Texas) LLC, as administrative agent and the banks party thereto, with TD Securities (USA) LLC, as lead arranger and bookrunner, dated March 18, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on March 21, 2016; File No. 001-32395). |
| 12* | Computation of Ratio of Earnings to Fixed Charges. |
| 21* | List of Subsidiaries of ConocoPhillips. |
| 23.1* | Consent of Ernst & Young LLP. |
| 23.2* | Consent of DeGolyer and MacNaughton. |
| 31.1* | Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934. |
| 31.2* | Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934. |
| 32* | Certifications pursuant to 18 U.S.C. Section 1350. |
| 99* | Report of DeGolyer and MacNaughton. |
| 101.INS* | XBRL Instance Document. |
| 101.SCH* | XBRL Schema Document. |
| 101.CAL* | XBRL Calculation Linkbase Document. |
| 101.DEF* | XBRL Definition Linkbase Document. |
| 101.LAB* | XBRL Labels Linkbase Document. |
| 101.PRE* | XBRL Presentation Linkbase Document. |

* Filed herewith.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

**CONOCOPHILLIPS**

| | |
|---|---|
| February 21, 2017 | */s/ Ryan M. Lance*<br>Ryan M. Lance<br>Chairman of the Board of Directors<br>and Chief Executive Officer |

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 21, 2017, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

| Signature | Title |
|---|---|
| */s/ Ryan M. Lance*<br>Ryan M. Lance | Chairman of the Board of Directors<br>and Chief Executive Officer<br>(Principal executive officer) |
| */s/ Don E. Wallette, Jr.*<br>Don E. Wallette, Jr. | Executive Vice President, Finance,<br>Commercial and Chief Financial Officer<br>(Principal financial officer) |
| */s/ Glenda M. Schwarz*<br>Glenda M. Schwarz | Vice President and Controller<br>(Principal accounting officer) |

| | |
|---|---|
| */s/ Richard L. Armitage*<br>Richard L. Armitage | Director |
| */s/ Richard H. Auchinleck*<br>Richard H. Auchinleck | Director |
| */s/ Charles E. Bunch*<br>Charles E. Bunch | Director |
| */s/ James E. Copeland, Jr.*<br>James E. Copeland, Jr. | Director |
| */s/ Gay Huey Evans*<br>Gay Huey Evans | Director |
| */s/ John V. Faraci*<br>John V. Faraci | Director |
| */s/ Jody Freeman*<br>Jody Freeman | Director |
| */s/ Arjun N. Murti*<br>Arjun N. Murti | Director |
| */s/ Robert A. Niblock*<br>Robert A. Niblock | Director |
| */s/ Harald J. Norvik*<br>Harald J. Norvik | Director |

## Board of Directors

(As of Feb. 21, 2017)

**Richard L. Armitage**
President, Armitage International LLC, Former U.S. Deputy Secretary of State

**Richard H. Auchinleck**
Former President and Chief Executive Officer, Gulf Canada Resources Limited

**Charles E. Bunch**
Former Chairman and Chief Executive Officer, PPG Industries, Inc.

**James E. Copeland, Jr.**
Former Chief Executive Officer, Deloitte & Touche and Deloitte Touche Tohmatsu

**John V. Faraci**
Former Chairman and Chief Executive Officer, International Paper Company

**Jody Freeman**
Archibald Cox Professor of Law, Harvard Law School

**Gay Huey Evans, OBE**
Deputy Chairman, The Financial Reporting Council and Non-Executive Director, Bank Itau BBA International Limited and Standard Chartered PLC

**Ryan M. Lance**
Chairman and Chief Executive Officer, ConocoPhillips

**Arjun N. Murti**
Senior Advisor, Warburg Pincus and Retired Partner, Goldman, Sachs & Co.

**Robert A. Niblock**
Chairman, President and Chief Executive Officer, Lowe's Companies, Inc.

**Harald J. Norvik**
Former Chairman, President and Chief Executive Officer, Statoil

## Executive Leadership Team

(As of Feb. 21, 2017)

**Ryan M. Lance**
Chairman and Chief Executive Officer

**Matt J. Fox**
Executive Vice President, Strategy, Exploration and Technology

**Al J. Hirshberg**
Executive Vice President, Production, Drilling and Projects

**Don E. Wallette, Jr.**
Executive Vice President, Finance, Commercial and Chief Financial Officer

**Janet Langford Carrig**
Senior Vice President, Legal, General Counsel and Corporate Secretary

**Andrew D. Lundquist**
Senior Vice President, Government Affairs

**Ellen R. DeSanctis**
Vice President, Investor Relations and Communications

**James D. McMorran**
Vice President, Human Resources and Real Estate and Facilities Services

## Explore ConocoPhillips

### Fact Sheets

The ConocoPhillips fact sheets provide detailed operational updates for each of the company's six segments. The fact sheets are updated annually and are available at *www.conocophillips.com/factsheets.*

### Sustainability Report

The ConocoPhillips Sustainability Report provides an overview of the company's sustainable development programs and metrics. The 2016 Sustainability Report will be available in June at *www.conocophillips.com/sustainability.*

Certain disclosures in this annual report may be considered "forward-looking" statements. These are made pursuant to "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The "Cautionary Statement" in the Management's Discussion and Analysis in ConocoPhillips' 2016 Form 10-K should be read in conjunction with such statements.

"ConocoPhillips," "the company," "we," "us" and "our" are used interchangeably in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries.

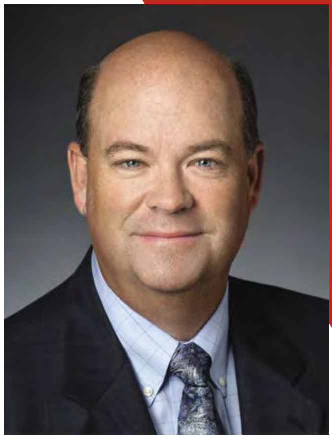
**Cautionary Note to U.S. Investors –** The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves. We use the term "resource" in this annual report, which the SEC's guidelines prohibit us from including in filings with the SEC. U.S. investors are urged to consider closely the oil and gas disclosures in our Form 10-K and other reports and filings with the SEC. Copies are available from the SEC and on the ConocoPhillips website.

**Use of Non-GAAP Financial Information –** This annual report includes non-GAAP financial terms that are included to help facilitate comparisons of company operating performance across periods and with peer companies. Operating costs is defined by the company as the sum of production and operation expenses, selling, general and administrative expenses, and exploration general and administrative expenses, geological and geophysical and lease rental and other expenses. Breakeven price is the Brent price at which cash from operating activities equals the capital expenditures and investments required to maintain flat production, working capital changes associated with investing activities and dividends paid.

ConocoPhillips

2017 Annual Report

# Letter to **Shareholders**



Dear Fellow Shareholders:

ConocoPhillips has taken a leadership stance with a new approach to the E&P business, one designed to deliver predictable performance and superior returns across a wide range of commodity prices. We introduced a disciplined, returns-focused value proposition in late 2016 and as energy markets began to recover in 2017, we took several key steps to accelerate and differentiate our offering to the market.

At the core of our unique value proposition is a clear set of strategic priorities for cash flow allocation: maintain flat production and pay our dividend; grow our dividend; maintain a strong balance sheet; pay out 20 to 30 percent of cash from operations to shareholders annually through the dividend and share buybacks; and invest in high-return projects to expand cash flow. Our strategy is aimed at creating value even when prices are below $50 per barrel, while also allowing shareholders to benefit during periods of higher prices.

When we debuted our value proposition we were met with skepticism. Some challenged whether we could execute our bold set of priorities. Others questioned whether there was a market for an E&P company focused on returns rather than growth. Just over a year later, we believe we have addressed both concerns. 2017 was a transformational year for the company as we made strong progress on our strategic priorities. Among our key achievements, we:

- Reduced exposure to North American natural gas and oil sands assets through dispositions that generated $16 billion.
- Generated cash from operations that exceeded capital spending by $2.5 billion.
- Returned 61 percent of cash from operations to shareholders through dividends and share buybacks.
- Reduced debt by almost 30 percent to $19.7 billion and improved our credit rating.
- Strengthened our position to deliver improved cash and financial returns even at crude prices below $50 per barrel WTI.

Importantly, our talented workforce also met or exceeded our 2017 operational goals while achieving one of our best years of safety performance. We never take safety for granted, nor do we waver from our commitment to environmental, social and governance (ESG) performance. We took a visible step to sustain our ESG leadership by announcing a target to reduce greenhouse gas emissions intensity by 5 to 15 percent by 2030.

We believe the market response to our value proposition has been positive. In 2017, we generated a total shareholder return of 12 percent, which was differential to most other E&P companies. In addition, we note that there is now growing support across the sector for value propositions like ours, which offer a more disciplined approach to the business.

By all accounts, 2017 was an exceptional year for ConocoPhillips. We performed well and we're confident our value proposition is sound. So, we're building on that momentum and sticking to our priorities, even as oil prices recover. As evidence, in January we paid down $2.25 billion of debt. In February, we announced a 7.5 percent increase in our quarterly dividend and a 33 percent increase in our planned 2018 share buybacks. We took these actions while maintaining discipline on our low cost of supply investment plan.

I'll end this note by thanking our shareholders, world-class workforce and board of directors for their contributions to ConocoPhillips. We can all take pride in the company we have become — stronger, more focused, and built to thrive in an environment of volatile prices. We intend to make 2018 another strong year by safely executing and delivering on our commitments.

Ryan M. Lance

**Ryan M. Lance**
Chairman and Chief Executive Officer
Feb. 20, 2018

# 2017

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

# Form 10-K

(Mark One)

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2017**

OR

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

For the transition period from ____________ to ____________

Commission file number: **001-32395**

# ConocoPhillips

*(Exact name of registrant as specified in its charter)*

| **Delaware** | **01-0562944** |
|---|---|
| *(State or other jurisdiction of incorporation or organization)* | *(I.R.S. Employer Identification No.)* |

**600 North Dairy Ashford**
**Houston, TX 77079**
*(Address of principal executive offices) (Zip Code)*

Registrant's telephone number, including area code: **281-293-1000**

Securities registered pursuant to Section 12(b) of the Act:

| **Title of each class** | **Name of each exchange on which registered** |
|---|---|
| Common Stock, $.01 Par Value | New York Stock Exchange |
| 7% Debentures due 2029 | New York Stock Exchange |

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. [x] Yes [ ] No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. [ ] Yes [x] No

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). [x] Yes [ ] No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

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

Large accelerated filer [x] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]
Emerging growth company [ ]

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

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

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $43.96, was $54.0 billion.

The registrant had 1,174,577,506 shares of common stock outstanding at January 31, 2018.

**Documents incorporated by reference:**

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 15, 2018 (Part III)

## TABLE OF CONTENTS

# PART I

Unless otherwise indicated, "the company," "we," "our," "us" and "ConocoPhillips" are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Items 1 and 2—Business and Properties, contain forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. 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 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 the heading "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 70.

## Items 1 and 2. BUSINESS AND PROPERTIES

## CORPORATE STRUCTURE

ConocoPhillips is the world's largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. ConocoPhillips was incorporated in the state of Delaware on November 16, 2001, in connection with, and in anticipation of, the merger between Conoco Inc. and Phillips Petroleum Company. The merger between Conoco and Phillips was consummated on August 30, 2002.

In April 2012, ConocoPhillips completed the separation of the downstream business into an independent, publicly traded energy company, Phillips 66.

Headquartered in Houston, Texas, we have operations and activities in 17 countries. Our diverse portfolio includes resource-rich North American tight oil and oil sands assets; lower-risk conventional assets in North America, Europe, Asia and Australia; several liquefied natural gas (LNG) developments; and an inventory of global conventional and unconventional exploration prospects.

At December 31, 2017, ConocoPhillips employed approximately 11,400 people worldwide.

We operate in a commodity-price driven industry, subject to volatility. In line with this view, we set our operating plan for 2017, defining our cash allocation priorities which would be reinforced and partly funded by sales of noncore assets during the year. In November 2016, we announced our plan to generate $5 billion to $8 billon of proceeds over two years by optimizing our portfolio to focus on value-preserving, low cost-of-supply projects that strategically fit our development plans. In 2017, our total consideration from asset dispositions was approximately $16 billion. We disposed of assets including our 50 percent nonoperated interest in the Foster Creek Christina Lake (FCCL) Partnership, as well as the majority of our western Canada gas assets, and our interest in the San Juan Basin gas asset. Proceeds from dispositions were directed towards allocation priorities and our asset sales, see the Business Environment and Executive Overview section within Management's Discussion and Analysis and Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements, respectively.

## SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic information, see Note 23—Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2017, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

The information listed below appears in the "Oil and Gas Operations" disclosures following the Notes to Consolidated Financial Statements and is incorporated herein by reference:

- Proved worldwide crude oil, natural gas liquids, natural gas and bitumen reserves.
- Net production of crude oil, natural gas liquids, natural gas and bitumen.
- Average sales prices of crude oil, natural gas liquids, natural gas and bitumen.
- Average production costs per barrel of oil equivalent (BOE).
- Net wells completed, wells in progress and productive wells.
- Developed and undeveloped acreage.

The following table is a summary of the proved reserves information included in the "Oil and Gas Operations" disclosures following the Notes to Consolidated Financial Statements. Approximately 77 percent of our proved reserves are located in politically stable countries that belong to the Organization for Economic Cooperation and Development. Natural gas reserves are converted to BOE based on a 6:1 ratio: six thousand cubic feet (MCF) of natural gas converts to one BOE. See Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance the understanding of the following summary reserves table.

| | Millions of Barrels of Oil Equivalent | | |
|---|---|---|---|
| **Net Proved Reserves at December 31** | **2017** | 2016 | 2015 |
| Crude oil | | | |
| Consolidated operations | **2,322** | 2,047 | 2,270 |
| Equity affiliates | **83** | 88 | 93 |
| Total Crude Oil | **2,405** | 2,135 | 2,363 |
| Natural gas liquids | | | |
| Consolidated operations | **354** | 457 | 508 |
| Equity affiliates | **45** | 47 | 50 |
| Total Natural Gas Liquids | **399** | 504 | 558 |
| Natural gas | | | |
| Consolidated operations | **1,267** | 1,807 | 1,988 |
| Equity affiliates | **717** | 730 | 878 |
| Total Natural Gas | **1,984** | 2,537 | 2,866 |
| Bitumen | | | |
| Consolidated operations | **250** | 159 | 687 |
| Equity affiliates | **-** | 1,089 | 1,706 |
| Total Bitumen | **250** | 1,248 | 2,393 |
| Total consolidated operations | **4,193** | 4,470 | 5,453 |
| Total equity affiliates | **845** | 1,954 | 2,727 |
| Total company | **5,038** | 6,424 | 8,180 |

Total production, including Libya, of 1,377 thousand barrels of oil equivalent per day (MBOED) decreased 12 percent in 2017 compared with 2016. The decrease in total average production primarily resulted from noncore asset dispositions, including our Canada and San Juan transactions in 2017 and the sale of our interest in the Block B production sharing contract (PSC) in Indonesia in 2016, and normal field decline. The decrease in production was partly offset by production from major developments, including tight oil plays in the Lower 48; Malikai and the Kebabangan gas field in Malaysia; Surmont in Canada; and APLNG in Australia. Improved drilling and well performance in Alaska, Norway and China also partly offset the decrease in production. Excluding Libya, our 2017 production was 1,356 MBOED. Adjusted for the impact of closed and planned dispositions of 191 MBOED in 2017 and 434 MBOED in 2016 and Libya, underlying production increased 32 MBOED, or 3 percent, compared with 2016.

Our worldwide annual average realized price was $39.19 per BOE in 2017, an increase of 38 percent compared with $28.35 per BOE in 2016, reflecting higher average realized prices across all commodities. Our worldwide annual average crude oil price increased 27 percent in 2017, from $40.86 per barrel in 2016 to $51.96 per barrel in 2017. Additionally, our worldwide annual average natural gas liquids prices increased 51 percent, from $16.68 per barrel in 2016 to $25.22 per barrel in 2017. Our worldwide annual average natural gas price increased 36 percent, from $3.00 per MCF in 2016 to $4.07 per MCF in 2017. Average annual bitumen prices also increased 48 percent, from $15.27 per barrel in 2016 to $22.66 per barrel in 2017.

## ALASKA

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas and natural gas liquids. We are the largest crude oil producer in Alaska and have major ownership interests in two of North America’s largest oil fields located on Alaska’s North Slope: Prudhoe Bay and Kuparuk. We also have a significant operating interest in the Alpine Field, located on the Western North Slope. Additionally, we are one of Alaska’s largest owners of state, federal and fee exploration leases, with approximately 1 million net undeveloped acres at year-end 2017. Alaska operations contributed 22 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

| | | | 2017 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD* | Natural Gas MMCFD** | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Greater Prudhoe Area | 36.1% | BP | 88 | 5 | 89 |
| Greater Kuparuk Area | 52.2−55.5 | ConocoPhillips | 53 | 1 | 53 |
| Western North Slope | 78.0 | ConocoPhillips | 40 | 1 | 40 |
| Total Alaska | | | 181 | 7 | 182 |

**Thousands of barrels per day.*
***Millions of cubic feet per day.*

### *Greater Prudhoe Area*

The Greater Prudhoe Area includes the Prudhoe Bay Field and five satellite fields, as well as the Greater Point McIntyre Area fields. Prudhoe Bay, the largest oil field on Alaska’s North Slope, is the site of a large waterflood and enhanced oil recovery operation, as well as a gas plant which processes natural gas to recover natural gas liquids before reinjection into the reservoir. Prudhoe Bay’s satellites are Aurora, Borealis, Polaris, Midnight Sun and Orion, while the Point McIntyre, Niakuk, Raven, Lisburne and North Prudhoe Bay State fields are part of the Greater Point McIntyre Area.

*Greater Kuparuk Area*
We operate the Greater Kuparuk Area, which consists of the Kuparuk Field and four satellite fields: Tarn, Tabasco, Meltwater and West Sak. Kuparuk is located 40 miles west of Prudhoe Bay. Field installations include three central production facilities which separate oil, natural gas and water, as well as a separate seawater treatment plant. Development drilling at Kuparuk consists of rotary-drilled wells and horizontal multi-laterals from existing well bores utilizing coiled-tubing drilling.

Drill Site 2S, in the southwestern area of the Kuparuk Field, was sanctioned in October 2014. First oil was achieved in October 2015, and completion of the first phase of the project was achieved in 2016.

The 1H Northeast West Sak (NEWS) oil development targeting the West Sak reservoir in the Kuparuk River Unit, was sanctioned in March 2015. First production was achieved in the fourth quarter of 2017.

*Western North Slope*
On the Western North Slope, we operate the Colville River Unit, which includes the Alpine Field and three satellite fields: Nanuq, Fiord and Qannik. Alpine is located 34 miles west of Kuparuk. In 2015, first oil was achieved at Alpine West CD5, a new drill site which extends the Alpine reservoir west into the National Petroleum Reserve-Alaska (NPR-A). During the year, we continued drilling additional wells using the available well slots on the pad.

The Greater Mooses Tooth Unit, the first unit established entirely within the NPR-A, was formed in 2008. In 2017, we began construction in the unit, which is currently planned to have two drill sites; Greater Mooses Tooth #1 and #2, with expected first oil in 2018 and 2021, respectively.

*Cook Inlet Area*
In January 2018, we sold our interest in the Kenai LNG Facility in the Cook Inlet Area. The facility, which consisted of a 1.6 million-tons-per-year capacity plant, as well as docking and loading facilities for LNG tankers, had no LNG export program in 2017 due to market conditions.

*Point Thomson*
In the first quarter of 2017, we recorded an asset impairment and assigned our 4.9 percent interest in the Point Thomson unit, located approximately 60 miles east of Prudhoe Bay, to the other owners of the field.

*Alaska North Slope Gas*
In 2016, we, along with affiliates of Exxon Mobil Corporation, BP p.l.c. and Alaska Gasline Development Corporation (AGDC), a state-owned corporation (collectively, the "AKLNG co-venturers"), completed preliminary front-end engineering and design (pre-FEED) technical work for a potential LNG project which would liquefy and export natural gas from Alaska's North Slope and deliver it to market. In September 2016, we, along with the affiliates of ExxonMobil and BP, indicated our intention not to progress into the next phase of the project due to changes in the economic environment. AGDC is continuing to progress the project and has recently signed several Memorandums of Understanding with various potential LNG buyers in Asia. We remain supportive of AGDC's efforts to advance the project and intend to make our equity gas available for sale to the project at mutually agreed, commercially reasonable terms.

*Exploration*
Appraisal of the Willow Discovery, located in the northeast portion of the National Petroleum Reserve-Alaska, continued throughout 2017 with the acquisition of 3-D seismic which is currently being processed. In 2018, we will continue appraisal of the discovery with drilling of additional wells. Further exploration of other state and federal leases is planned in 2018.

We were successful in state and federal lease sales in the North Slope in the fourth quarter of 2017, where we were the high bidder on 13 tracts for a total of approximately 78,000 net acres.

*Acquisition*
In January 2018, we entered into an agreement to acquire certain oil and gas assets in Alaska. The acquisition is subject to regulatory approval. We will have a 100 percent interest in approximately 1.2 million acres of exploration and development lands, including the Willow Discovery. For additional information, see Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements.

*Transportation*
We transport the petroleum liquids produced on the North Slope to south central Alaska through an 800-mile pipeline that is part of Trans-Alaska Pipeline System (TAPS). We have a 29.1 percent ownership interest in TAPS, and we also have ownership interests in the Alpine, Kuparuk and Oliktok pipelines on the North Slope.

Our wholly owned subsidiary, Polar Tankers, Inc., manages the marine transportation of our North Slope production, using five company-owned, double-hulled tankers, and charters third-party vessels as necessary. The tankers deliver oil from Valdez, Alaska, primarily to refineries on the west coast of the United States.

## LOWER 48

The Lower 48 segment consists of operations located in the U.S. Lower 48 states and the Gulf of Mexico. The Lower 48 business is organized within three regions covering the Gulf Coast, Mid-Continent and Rockies. As a result of tight oil opportunities, we have directed our investments toward certain shorter cycle time, low cost-of-supply plays. We disposed of several noncore assets within the Lower 48 in 2017, including our interests in the San Juan Basin and the Panhandle. We hold 10.4 million net onshore and offshore acres in the Lower 48. In 2017, the Lower 48 contributed 30 percent of our worldwide liquids production and 27 percent of our natural gas production.

| | | | 2017 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Eagle Ford | Various% | Various | 107 | 155 | 133 |
| Gulf of Mexico | Various | Various | 15 | 13 | 17 |
| Gulf Coast—Other | Various | Various | 5 | 11 | 7 |
| Total Gulf Coast | | | 127 | 179 | 157 |
| Permian | Various | Various | 41 | 132 | 63 |
| Barnett | Various | Various | 4 | 34 | 10 |
| Anadarko Basin | Various | Various | 4 | 91 | 19 |
| Total Mid-Continent | | | 49 | 257 | 92 |
| Bakken | Various | Various | 56 | 56 | 65 |
| Wyoming/Uinta | Various | Various | - | 84 | 14 |
| Niobrara | Various | Various | 2 | 3 | 3 |
| San Juan | Various | Various | 15 | 319 | 68 |
| Total Rockies | | | 73 | 462 | 150 |
| Total U.S. Lower 48 | | | 249 | 898 | 399 |

*Onshore*
We hold 10.4 million net acres of onshore conventional and unconventional acreage in the Lower 48, the majority of which is either held by production or owned by the company. Our unconventional holdings total approximately 1.8 million net acres in the following areas:

- 630,000 net acres in the Bakken, located in North Dakota and eastern Montana.
- 210,000 net acres in the Eagle Ford, located in South Texas.
- 134,000 net acres in the Permian, located in West Texas and southeastern New Mexico.

- 98,000 net acres in the Niobrara, located in northeastern Colorado.
- 66,000 net acres in the Barnett, located in north central Texas.
- 639,000 net acres in other unconventional exploration plays.

The majority of our 2017 onshore production originated from the Eagle Ford; San Juan, which we disposed of during the year; Bakken; and Permian. Onshore activities in 2017 were centered mostly on continued development of assets, with an emphasis on areas with low cost of supply, particularly in growing unconventional plays. The 2017 drilling activity levels increased relative to 2016 due to higher capital spending. Our major focus areas in 2017 included the following:

- Eagle Ford—The Eagle Ford continued full-field development in 2017. We operated six rigs on average in 2017, resulting in 133 operated wells drilled and 94 operated wells brought online. Production decreased 17 percent in 2017 compared with 2016, and reached a net peak of 164 MBOED, compared with 176 MBOED in 2016.
- Bakken—We operated four rigs throughout the year in the Bakken. We continued our pad drilling with 87 operated wells drilled during the year and 64 operated wells brought online. We achieved net peak production of 75 MBOED in 2017, compared with 72 MBOED in 2016.
- Permian Basin—The Permian Basin is an area where we are leveraging our conventional legacy position by utilizing new technology to improve the ultimate recovery and value from these fields. This technology should also identify new, unconventional plays across the region. We hold approximately 1 million net acres in the Permian, which includes 134,000 net unconventional acres. The Permian Basin produced 63 MBOED in 2017, staying essentially flat with 2016, including 19 MBOED of unconventional production.

We completed the sale of our interests in the San Juan Basin on July 31, 2017, and Panhandle assets on September 29, 2017. Production from the assets sold was 74 MBOED, approximately 19 percent of total Lower 48 segment production in 2017. For additional information on our asset dispositions, see Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements.

*Gulf of Mexico*
At year-end 2017, our portfolio of producing properties in the Gulf of Mexico primarily consisted of one operated field and three fields operated by co-venturers, totaling approximately 68,000 net acres, including:

- 75 percent operated working interest in the Magnolia Field in Garden Banks Blocks 783 and 784.
- 15.9 percent nonoperated working interest in the unitized Ursa Field located in the Mississippi Canyon Area.
- 15.9 percent nonoperated working interest in the Princess Field, a northern subsalt extension of the Ursa Field.
- 12.4 percent nonoperated working interest in the unitized K2 Field, comprised of seven blocks in the Green Canyon Area.

## *Exploration*

- *Conventional Exploration*
  At December 31, 2017, we held approximately 5,000 net acres in the deepwater Gulf of Mexico.

  Our 30 percent nonoperated working interest in the Shenandoah discovery was announced in 2009. In early 2017, the sixth Shenandoah well, Shenandoah WR52-3, reached total depth and was followed by the drilling of a sidetrack well from Shenandoah WR52-3. Following the suspension of appraisal activity by the operator during the year, we recorded dry hole and leasehold impairment expense for the entire development. On December 19, 2017, we elected to withdraw from the Shenandoah leases. The withdrawal was effective February 17, 2018.

- *Unconventional Exploration*
  Our onshore focus areas include the Niobrara in the Denver-Julesburg Basin and the Permian in the Delaware Basin, as well as several emerging plays. We continue to assess and appraise these and other unconventional opportunities. In 2016 and 2017, we drilled a total of five operated unconventional wells in the Powder River Basin, four of which were expensed as dry holes in November 2017. The fifth Powder River Basin well was expensed as a dry hole in January 2018.

**Facilities**
*Golden Pass LNG Terminal*
We have a 12.4 percent ownership interest in the Golden Pass LNG Terminal and affiliated Golden Pass Pipeline, with a combined net book value of approximately $247 million at December 31, 2017. It is located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal became commercially operational in May 2011. We hold terminal and pipeline capacity for the receipt, storage and regasification of the LNG purchased from Qatar Liquefied Gas Company Limited (3) (QG3) and the transportation of regasified LNG to interconnect with major interstate natural gas pipelines. Utilization of the terminal has been and is expected to be limited, as market conditions currently favor the flow of LNG to European and Asian markets. As a result, we are evaluating opportunities to optimize the value of the terminal facilities.

*Other*

- Lost Cabin Gas Plant—We operate and own a 46 percent interest in the Lost Cabin Gas Plant, a 246 million cubic-feet-per-day capacity natural gas processing facility in Lysite, Wyoming.
- Helena Condensate Processing Facility—We operate and own the Helena Condensate Processing Facility, a 110,000 barrel-per-day condensate processing plant located in Kenedy, Texas.
- Sugarloaf Condensate Processing Facility—We operate and own an 87.5 percent interest in the Sugarloaf Condensate Processing Facility, a 30,000 barrel-per-day condensate processing plant located near Pawnee, Texas.
- Bordovsky Condensate Processing Facility—We operate and own the Bordovsky Condensate Processing Facility, a 15,000 barrel-per-day condensate processing plant located in Kenedy, Texas.

CANADA

Our Canadian operations mainly consist of an oil sands development in the Athabasca Region of northeastern Alberta and a liquids-rich unconventional play in western Canada. In 2017, operations in Canada contributed 16 percent of our worldwide liquids production and 6 percent of our natural gas production.

| | | | 2017 | | | |
|---|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Bitumen MBD | Total MBOED |
| **Average Daily Net Production** | | | | | | |
| Western Canada | Various% | Various | 12 | 187 | - | 43 |
| Surmont | 50.0 | ConocoPhillips | - | - | 59 | 59 |
| Foster Creek | 50.0 | Cenovus | - | - | 26 | 26 |
| Christina Lake | 50.0 | Cenovus | - | - | 37 | 37 |
| Total Canada | | | 12 | 187 | 122 | 165 |

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Production from the assets sold was 103 MBOED, approximately 62 percent of the total Canada segment production in 2017. For additional information on our asset dispositions, see Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements.

*Oil Sands*
Our bitumen resources in Canada are produced via an enhanced thermal oil recovery method called steam-assisted gravity drainage (SAGD), whereby steam is injected into the reservoir, effectively liquefying the heavy bitumen, which is recovered and pumped to the surface for further processing. We hold approximately 0.6 million net acres of land in the Athabasca Region of northeastern Alberta.

Surmont—The Surmont oil sands leases are located approximately 35 miles south of Fort McMurray, Alberta. Surmont is a 50/50 joint venture with Total S.A. The second phase of the Surmont project achieved first production in 2015, and production continued to ramp up in 2017.

*Exploration*
We hold exploration acreage in three areas of Canada: onshore western Canada, the Mackenzie Delta/Beaufort Sea Region and the Arctic Islands. Our primary exploration focus is on unconventional plays in western Canada.

- *Unconventional Exploration*
  We hold approximately 0.1 million net acres in the emerging Montney play in northeast British Columbia and 0.2 million net acres in Canol Northwest Territories. Our Montney activity in 2017 included completing two and bringing onstream six appraisal wells and acquiring approximately 27,000 additional net acres. Late appraisal drilling activity will continue in 2018 to further explore the area's resource potential.

- *Conventional Exploration*
  Surrender of Interest documents for our 30 percent nonoperated working interest in six exploration licenses in the Shelburne Basin, offshore Nova Scotia, were submitted on December 15, 2017, to initiate the exit process, following previously announced results of the two-well exploration drilling campaign at Cheshire and Monterey Jack.

## EUROPE AND NORTH AFRICA

The Europe and North Africa segment consists of operations and exploration activities in Norway, the United Kingdom and Libya. In 2017, operations in Europe and North Africa contributed 18 percent of our worldwide liquids production and 15 percent of natural gas production.

**Norway**

| | | | 2017 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Greater Ekofisk Area | 35.1% | ConocoPhillips | 57 | 50 | 65 |
| Alvheim | 20.0 | Aker BP | 15 | 13 | 17 |
| Heidrun | 24.0 | Statoil | 13 | 30 | 18 |
| Other | Various | Statoil | 16 | 107 | 34 |
| Total Norway | | | 101 | 200 | 134 |

The Greater Ekofisk Area is located approximately 200 miles offshore Stavanger, Norway, in the North Sea, and comprises three producing fields: Ekofisk, Eldfisk and Embla. Crude oil is exported to Teesside, England, and the natural gas is exported to Emden, Germany. The Ekofisk and Eldfisk fields consist of several production platforms and facilities, including the Ekofisk South and Eldfisk II developments which achieved first production in 2013 and 2015, respectively. Continued development drilling in the Greater Ekofisk Area will contribute additional production over the coming years, as additional wells come online.

The Alvheim Field is located in the northern part of the North Sea near the border with the U.K. sector, and consists of a floating production, storage and offloading (FPSO) vessel and subsea installations. Produced crude oil is exported via shuttle tankers, and natural gas is transported to the Scottish Area Gas Evacuation (SAGE) terminal at St. Fergus, Scotland, through the SAGE pipeline.

The Heidrun Field is located in the Norwegian Sea. Produced crude oil is stored in a floating storage unit and exported via shuttle tankers. Part of the natural gas is currently injected into the reservoir for optimization of crude oil production, some gas is transported to Europe via gas processing terminals in Norway, while the remainder is transported for use as feedstock in a methanol plant in Norway, in which we own an 18 percent interest.

We also have varying ownership interests in five other producing fields in the Norway sector of the North Sea, as well as the Aasta Hansteen development in the Norwegian Sea. The operator is planning for first gas for Aasta Hansteen by late 2018.

*Exploration*
In 2017, we participated in the Korpfjell Well in the Barents Sea and the Carmen Well in the Heidrun Area of Norway, both of which made gas discoveries. The Carmen Well was considered a discovery and is currently under evaluation, while the Korpfjell Well is not considered commercial. In 2017, we were awarded four new exploration licenses including the PL865, PL888, PL890 and PL891; and two acreage additions PL053C and PL782SC. Additionally, two new licenses, PL775 and PL626, were captured through farm-in.

*Transportation*
We own a 35.1 percent interest in the Norpipe Oil Pipeline System, a 220-mile pipeline which carries crude oil from Ekofisk to a crude oil stabilization and natural gas liquids processing facility in Teesside, England.

**United Kingdom**

| | | | 2017 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Britannia | 58.7% | ConocoPhillips | 3 | 68 | 14 |
| Britannia Satellites | 26.3–87.5* | ConocoPhillips | 13 | 84 | 27 |
| J-Area | 32.5–36.5 | ConocoPhillips | 9 | 60 | 19 |
| Southern North Sea | Various | ConocoPhillips | - | 46 | 8 |
| East Irish Sea | 100.0 | Spirit Energy | - | 14 | 2 |
| Other | Various | Various | 4 | 4 | 5 |
| Total United Kingdom | | | 29 | 276 | 75 |

**Includes the Chevron-operated Alder Field, ConocoPhillips equity 26.3%.*

Britannia is one of the largest natural gas and condensate fields in the North Sea. We assumed operatorship of Britannia in August 2015, following the acquisition of third-party equity in Britannia Operator Limited, which is now wholly owned by ConocoPhillips. Condensate is delivered through the Forties Pipeline to an oil stabilization and processing plant near the Grangemouth Refinery in Scotland, while natural gas is transported through Britannia's line to St. Fergus, Scotland. The Britannia satellite fields, Callanish, Brodgar, Enochdhu and Alder, produce via subsea manifolds and pipelines linked to the Britannia Platform.

The J-Area consists of the Judy/Joanne, Jade and Jasmine fields, located in the U.K. Central North Sea. The J-Area gas is processed on the Judy Platform and transported through the Central Area Transmission System Pipeline, while liquids are transported to Teesside through the Norpipe system. A J-Area development drilling campaign commenced in 2017, which is expected to provide additional volumes in the coming years as wells are brought online.

We have various ownership interests in several producing gas fields in the Rotliegendes and Carboniferous areas of the Southern North Sea. Decommissioning activity in the Southern North Sea is ongoing. Our interests in the East Irish Sea include the Millom, Dalton and Calder fields, which are operated on our behalf by a third party.

We own a 24 percent interest in the Clair Field, located in the Atlantic Margin. Clair Ridge is the second phase of development for the Clair Field and is comprised of a 36-slot drilling and production facility with a bridge-linked accommodation and utilities platform. The new facilities will tie into existing oil and gas export pipelines to the Shetland Islands. Initial production for Clair Ridge is expected in 2018.

*Transportation*
We operate the Teesside oil and Theddlethorpe gas terminals in which we have 29.3 percent and 50 percent ownership interests, respectively. We also have a 100 percent ownership interest in the Rivers Gas Terminal, operated by a third party.

**Libya**

| | | | 2017 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Waha Concession | 16.3 % | Waha Oil Co. | 20 | 8 | 21 |
| Total Libya | | | 20 | 8 | 21 |

The Waha Concession consists of multiple concessions and encompasses nearly 13 million gross acres in the Sirte Basin. Our production operations in Libya and related oil exports were interrupted in mid-2013, as a result of the shutdown of the Es Sider crude oil export terminal at the end of July 2013. The Es Sider Terminal briefly reopened in the third quarter of 2014 and production and liftings resumed temporarily; however, further disruptions occurred in December 2014, and production was shut in again. Production resumed in Libya in October 2016. In 2017, we had 17 crude liftings from Es Sider. We expect a gradual, continued ramp-up in activity.

ASIA PACIFIC AND MIDDLE EAST

The Asia Pacific and Middle East segment has exploration and production operations in China, Indonesia, Malaysia and Australia; producing operations in Qatar and Timor-Leste; and exploration activities in Brunei. In 2017, operations in the Asia Pacific and Middle East segment contributed 14 percent of our worldwide liquids production and 52 percent of natural gas production.

**Australia and Timor Sea**

| | | | 2017 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Australia Pacific LNG | 37.5% | ConocoPhillips/ Origin Energy | - | 638 | 106 |
| Bayu-Undan | 56.9 | ConocoPhillips | 10 | 233 | 49 |
| Athena/Perseus | 50.0 | ExxonMobil | - | 34 | 6 |
| Total Australia and Timor Sea | | | 10 | 905 | 161 |

*Australia Pacific LNG*
Australia Pacific LNG Pty Ltd (APLNG), our joint venture with Origin Energy Limited and China Petrochemical Corporation (Sinopec), is focused on producing coalbed methane (CBM) from the Bowen and Surat basins in Queensland, Australia, to supply the domestic gas market and convert the CBM into LNG for export. Origin operates APLNG's upstream production and pipeline system, and we operate the downstream LNG facility, located on Curtis Island near Gladstone, Queensland, as well as the LNG export sales business.

Two fully subscribed 4.5-million-metric-tonnes-per-year LNG trains have been completed. Approximately 3,900 net wells are ultimately envisioned to supply both the domestic gas market and the LNG sales contracts. The wells are supported by gathering systems, central gas processing and compression stations, water treatment facilities, and an export pipeline connecting the gas fields to the LNG facilities. The first APLNG Train 1 cargo sailed in January 2016, and LNG sales continued throughout the year. APLNG Train 2 achieved first production in the third quarter of 2016. The LNG is being sold to Sinopec under 20-year sales agreements for 7.6 million metric tonnes of LNG per year, and Japan-based Kansai Electric Power Co., Inc. under a 20-year sales agreement for approximately 1 million metric tonnes of LNG per year.

APLNG has an $8.5 billion project finance facility, which was fully drawn down and had an outstanding balance of $7.9 billion at December 31, 2017. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility until the project achieves financial completion. In October 2016, we reached financial completion for Train 1, which reduced our associated guarantee by 60 percent. In August 2017, we reached financial completion for Train 2, which removed the remaining guarantee. For additional information, see Note 2—Variable Interest Entities (VIEs), Note 5—Investments, Loans and Long-Term Receivables, and Note 11—Guarantees, in the Notes to Consolidated Financial Statements.

*Bayu-Undan*
The Bayu-Undan gas condensate field is located in the Timor Sea Joint Petroleum Development Area between Timor-Leste and Australia. We also operate and own a 56.9 percent interest in the associated Darwin LNG Facility, located at Wickham Point, Darwin.

The Bayu-Undan natural gas recycle facility processes wet gas; separates, stores and offloads condensate, propane and butane; and re-injects dry gas back into the reservoir. In addition, a 310-mile natural gas pipeline connects the facility to the 3.5-million-metric-tonnes-per-year capacity Darwin LNG Facility. Produced natural gas is piped to the Darwin LNG Plant, where it is converted into LNG before being transported to international markets. In 2017, we sold 150 billion gross cubic feet of LNG primarily to utility customers in Japan.

A continuation of the Bayu-Undan Phase Three Development has been sanctioned with internal, joint venture and regulatory approval in March 2017. The project premise consists of one subsea and two platform wells, with drilling to commence in April 2018. Production is expected to commence in the third quarter of 2018.

*Athena/Perseus*
The Athena production license (WA-17-L) is located offshore Western Australia and contains part of the Perseus Field, which straddles the boundary with WA-1-L, an adjoining license area. Natural gas is produced from these licenses, which are due to expire in 2019.

*Greater Sunrise*
We have a 30 percent interest in the Greater Sunrise natural gas and condensate field located in the Timor Sea. Timor-Leste and Australia through engagement in a conciliation process under the United Nations Convention on the Law of the Sea have reached agreement on the central elements of a maritime boundary delimitation between them in the Timor Sea. The Governments' agreement, to be formalized in a new treaty, constitutes a package that addresses boundaries, the legal status of the Greater Sunrise gas field, the establishment of a Special Regime for Greater Sunrise, a pathway to development of the resource and the sharing of resulting revenue. Discussions are ongoing between the two Governments and the Sunrise co-venturers with respect to the development concept for Greater Sunrise. Until the Governments and the Sunrise co-venturers are aligned on a development concept, activities are currently restricted to compliance and social investment, maintaining relationships and continued engagement with the Governments for a future development option.

*Exploration*

- *Conventional Exploration*
  We operate three exploration permits in the Browse Basin, offshore northwest Australia, in which we own a 40 percent interest in permits WA-315-P, WA-398-P and TP 28, of the Greater Poseidon Area. The TP 28 Western Australia State exploration permit was granted for five years from January 2017, with a 40 percent working interest and was excised from the existing permits as agreed between state and federal regulators. Phase I of the Browse Basin drilling campaign in 2009/2010 resulted in three discoveries in the Greater Poseidon Area: Poseidon-1, Poseidon-2 and Kronos-1. Phase II of the drilling campaign resulted in five additional discoveries: Boreas-1, Zephyros-1, Proteus-1 SD2, Poseidon-North-1 and Pharos-1. All wells have been completed, plugged and abandoned.

  We operate two retention leases in the Bonaparte Basin, offshore northern Australia, where we own a 37.5 percent interest in leases NT/RL5 and NT/RL6, containing the Barossa and Caldita discoveries. A 3-D seismic survey was completed over the Barossa and Caldita fields in 2016. The drilling of the Barossa-5 and Barossa-6 appraisal wells was completed in 2017 with good quality, gas-bearing reservoir intersected at both. Additionally, the retention lease over the Barossa Discovery was renewed during the year.

**Indonesia**

| | | | 2017 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| South Sumatra | 45.0–54.0% | ConocoPhillips | 2 | 308 | 53 |
| Total Indonesia | | | 2 | 308 | 53 |

We operate three PSCs in Indonesia: The Corridor Block and South Jambi “B,” both located in South Sumatra, and Kualakurun in Central Kalimantan. Currently there is production from the Corridor Block.

*South Sumatra*
The Corridor PSC consists of five oil fields and seven natural gas fields in various stages of development. Natural gas is supplied from the Grissik and Suban gas processing plants to the Duri steamflood in central Sumatra and to markets in Singapore, Batam and West Java. Production from the South Jambi “B” PSC has reached depletion and field development has been suspended.

*Exploration*
We have a 60 percent working interest in the Kualakurun PSC, located in Central Kalimantan, which was signed in May 2015. This block has an area of approximately 2 million gross acres. During 2017, we acquired 2-D seismic data in the area.

*Transportation*
We are a 35 percent owner of a consortium company that has a 40 percent ownership in PT Transportasi Gas Indonesia, which owns and operates the Grissik to Duri and Grissik to Singapore natural gas pipelines.

## China

| | Interest | Operator | 2017 Liquids MBD | 2017 Natural Gas MMCFD | 2017 Total MBOED |
|---|---|---|---|---|---|
| **Average Daily Net Production** | | | | | |
| Penglai | 49.0 % | CNOOC | 30 | - | 30 |
| Panyu | 24.5 | CNOOC | 8 | - | 8 |
| Total China | | | 38 | - | 38 |

The Penglai 19-3, 19-9 and 25-6 fields are located in Bohai Bay Block 11/05. Production from the Phase 1 development of the Penglai 19-3 Field began in 2002. Phase 2 included six additional wellhead platforms and an FPSO vessel, and was fully operational by 2009.

As part of further development of the Penglai 19-9 Field, a new wellhead platform, which adds up to 62 wells, is progressing according to schedule, with 19 wells completed and brought online through December 2017.

We sanctioned the Penglai 19-3/19-9 Phase 3 Project in December 2015. This project will consist of three new wellhead platforms and a central processing platform. First oil from Phase 3 is expected in 2018.

The Panyu development, located in Block 15/34 in the South China Sea, is comprised of three oil fields: Panyu 4-2, Panyu 5-1 and Panyu 11-6. The production period for Panyu 4-2 and 5-1 will expire in 2018, and the production period for Panyu 11-6 will expire in 2022.

*Exploration*
In 2017, we participated in a successful appraisal well in the Penglai Field, which will support future development plans. In late 2017, we began a full-field 3-D seismic program at Penglai, covering Phase 3 and other future development opportunities. The program is expected to continue in 2018.

**Malaysia**

| | | | 2017 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| Siakap North-Petai | 21.0 % | Murphy | 3 | 1 | 3 |
| Gumusut | 29.0 | Shell | 29 | - | 29 |
| KBB | 30.0 | KPOC | 3 | 111 | 22 |
| Malikai | 35.0 | Shell | 12 | - | 12 |
| Total Malaysia | | | 47 | 112 | 66 |

We own interests in six PSCs in Malaysia. Three are located off the eastern Malaysian state of Sabah: Block G, Block J and the Kebabangan Cluster (KBBC). Three other blocks, Deepwater Block 3E, Block SK313 and Block WL4-00 are located off the eastern Malaysian state of Sarawak.

*Block G*
We have a 21 percent interest in the unitized Siakap North-Petai oil field, which began producing in the first quarter of 2014.

First production from the Malikai oil field was achieved in December 2016, with estimated net annual peak production of 21 MBOED expected in 2018. We own a 35 percent interest in Malikai. The Limbayong-2 appraisal well was drilled in 2013 and resulted in an oil discovery. The well was expensed in 2017.

*Block J*
First production from the Gumusut Field occurred from an early production system in 2012. Production from a permanent, semi-submersible floating production vessel was achieved in October 2014. Our ownership in the Gumusut Field is currently at 29 percent following the finalization of the unitization with Brunei and a redetermination of the Block J and Block K Malaysia Unit, both in 2017. Gumusut Phase 2 infill drilling is planned to start in 2018.

*KBBC*
We own a 30 percent interest in the KBBC PSC. Development of the KBB gas field commenced in 2011, and first production was achieved in November 2014. Development options for the Kamunsu East gas field are being evaluated.

*Exploration*
We own a 50 percent operated interest in Deepwater Block 3E, which encompasses approximately 480,000 gross acres offshore Sarawak. Seismic processing was completed in 2015. The Langsat-1 exploration well was drilled and expensed as a dry hole in 2017.

In the fourth quarter of 2016, we entered into a farm-in agreement to acquire a 50 percent interest in Block SK 313, a 1.4 million gross-acre exploration block, effective January 2017. Following completion of the Sadok-1 exploration well in January 2017, we assumed operatorship of the block from PETRONAS.

We were awarded Block WL4-00, which encompasses approximately 629,000 gross acres, in January 2017. We have a 50 percent operated interest in this block which includes the Salam-1 oil discovery.

We completed a 3-D seismic survey in Block SK 313 and Block WL4-00 in 2017. Further exploration drilling is expected to occur in 2018.

**Brunei**
*Exploration*
We have a 6.25 percent working interest in the deepwater Block CA-2 PSC. Exploration has been ongoing since September 2011, with natural gas discovered at the Kelidang NE-1 and Keratau-1 wells in 2013 and at the Keratau SW-1 Well in 2015. Evaluation of the results is ongoing.

**Qatar**

| | | | 2017 | | |
|---|---|---|---|---|---|
| | Interest | Operator | Liquids MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | |
| QG3 | 30.0 % | Qatargas Operating Company Limited | 21 | 369 | 83 |
| Total Qatar | | | 21 | 369 | 83 |

QG3 is an integrated development jointly owned by Qatar Petroleum (68.5 percent), ConocoPhillips (30 percent) and Mitsui & Co., Ltd. (1.5 percent). QG3 consists of upstream natural gas production facilities, which produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar's North Field over a 25-year life, in addition to a 7.8 million gross tonnes-per-year LNG facility. LNG is shipped in leased LNG carriers destined for sale globally.

QG3 executed the development of the onshore and offshore assets as a single integrated development with Qatargas 4 (QG4), a joint venture between Qatar Petroleum and Royal Dutch Shell plc. This included the joint development of offshore facilities situated in a common offshore block in the North Field, as well as the construction of two identical LNG process trains and associated gas treating facilities for both the QG3 and QG4 joint ventures. Production from the LNG trains and associated facilities is combined and shared.

OTHER INTERNATIONAL

The Other International segment includes exploration activities in Colombia and Chile.

**Colombia**
*Unconventional Exploration*
We have an 80 percent operated interest in the Middle Magdalena Basin Block VMM-3. The block extends over approximately 67,000 net acres and contains the Picoplata-1 well, which completed drilling in 2015 and testing in 2017. Socialization and environmental permitting activities are expected to continue throughout 2018.

In July 2017, ConocoPhillips Colombia Ventures Ltd. and Canacol Energy Colombia S.A. executed an Additional Contract for the exploration and exploitation of unconventional reservoirs in an area identified as the VMM-2 Block. As a result, ConocoPhillips Colombia Ventures Ltd. and Canacol Energy Colombia S.A. also executed a joint operating agreement. We have an 80 percent operated working interest in the block which extends over approximately 58,000 net acres and is contiguous to the VMM-3 Block.

In 2017, we relinquished our 70 percent nonoperated interests in the deep rights in the Santa Isabel Block and terminated the exploration and production contract for the VMM27 Block, both in the Middle Magdalena Basin.

**Chile**
*Exploration*
We have a 49 percent interest in the Coiron Block located in the Magallanes Basin in southern Chile. In December 2017, two wells drilled in 2016, were expensed as dry holes.

**Venezuela and Ecuador**
For discussion of our contingencies in Venezuela and Ecuador, see Note 12—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

OTHER

**Marketing Activities**
Our Commercial organization manages our worldwide commodity portfolio, which mainly includes natural gas, crude oil, bitumen, natural gas liquids and LNG. Marketing activities are performed through offices in the United States, Canada, Europe and Asia. In marketing our production, we attempt to minimize flow disruptions, maximize realized prices and manage credit-risk exposure. Commodity sales are generally made at prevailing market prices at the time of sale. We also purchase and sell third-party volumes to better position the company to satisfy customer demand while fully utilizing transportation and storage capacity.

*Natural Gas*
Our natural gas production, along with third-party purchased gas, is primarily marketed in the United States, Canada, Europe and Asia. Our natural gas is sold to a diverse client portfolio which includes local distribution companies; gas and power utilities; large industrials; independent, integrated or state-owned oil and gas companies; as well as marketing companies. To reduce our market exposure and credit risk, we also transport natural gas via firm and interruptible transportation agreements to major market hubs.

*Crude Oil, Bitumen and Natural Gas Liquids*
Our crude oil, bitumen and natural gas liquids revenues are derived from production in the United States, Canada, Australia, Asia, Africa and Europe. These commodities are primarily sold under contracts with prices based on market indices, adjusted for location, quality and transportation.

*LNG*
LNG marketing efforts are focused on equity LNG production facilities located in Australia and Qatar. LNG is primarily sold under long-term contracts with prices based on market indices.

**Energy Partnerships**
*Marine Well Containment Company (MWCC)*
We are a founding member of the MWCC, a non-profit organization formed in 2010, which provides well containment equipment and technology in the deepwater U.S. Gulf of Mexico. MWCC's containment system meets the U.S. Bureau of Safety and Environmental Enforcement requirements for a subsea well containment system that can respond to a deepwater well control incident in the U.S. Gulf of Mexico. For additional information, see Note 2—Variable Interest Entities (VIEs), in the Notes to Consolidated Financial Statements.

*Subsea Well Response Project (SWRP)*
In 2011, we, along with several leading oil and gas companies, launched the SWRP, a non-profit organization based in Stavanger, Norway, which was created to enhance the industry's capability to respond to international subsea well control incidents. Through collaboration with Oil Spill Response Limited, a non-profit organization in the United Kingdom, subsea well intervention equipment is available for the industry to use in the event of a subsea well incident. This complements the work being undertaken in the United States by MWCC.

*Oil Spill Response Removal Organizations (OSROs)*

We maintain memberships in several OSROs across the globe as a key element of our preparedness program in addition to internal response resources. Many of the OSROs are not-for-profit cooperatives owned by the member companies wherein we may actively participate as a member of the board of directors, steering committee, work group or other supporting role. Globally, our primary OSRO is Oil Spill Response Ltd. based in the U.K., with facilities in several other countries and the ability to respond anywhere in the world. In North America, our primary OSROs include the Marine Spill Response Corporation for the continental U.S. and Alaska Clean Seas and Ship Escort/Response Vessel System for the Alaska North Slope and Prince William Sound, respectively. Internationally, we maintain memberships in various regional OSROs including the Norwegian Clean Seas Association for Operating Companies, Australian Marine Oil Spill Center and Petroleum Industry of Malaysia Mutual Aid Group.

**Technology**

We have several technology programs that improve our ability to develop unconventional reservoirs, produce heavy oil economically with fewer emissions, improve the efficiency of our company's exploration program, increase recoveries from our legacy fields, and implement sustainability measures.

Our Optimized Cascade® LNG liquefaction technology business continues to be successful with the demand for new LNG plants. The technology has been licensed for use in 25 LNG trains around the world, with feasibility studies ongoing for additional trains.

## RESERVES

We have not filed any information with any other federal authority or agency with respect to our estimated total proved reserves at December 31, 2017. No difference exists between our estimated total proved reserves for year-end 2016 and year-end 2015, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2017.

## DELIVERY COMMITMENTS

We sell crude oil and natural gas from our producing operations under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Our commercial organization also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be the spot market or a combination of our reserves and the spot market. Worldwide, we are contractually committed to deliver approximately 1.7 trillion cubic feet of natural gas, including approximately 303 billion cubic feet related to the noncontrolling interests of consolidated subsidiaries, and 99 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2029. We expect to fulfill the majority of these delivery commitments with proved developed reserves. In addition, we anticipate using proved undeveloped reserves and spot market purchases to fulfill any remaining commitments. See the disclosure on "Proved Undeveloped Reserves" in the "Oil and Gas Operations" section following the Notes to Consolidated Financial Statements, for information on the development of proved undeveloped reserves.

## COMPETITION

We compete with private, public and state-owned companies in all facets of the E&P business. Some of our competitors are larger and have greater resources. Each of our segments is highly competitive, with no single competitor, or small group of competitors, dominating.

We compete with numerous other companies in the industry, including state-owned companies, to locate and obtain new sources of supply and to produce oil, bitumen, natural gas liquids and natural gas in an efficient, cost-effective manner. Based on statistics published in the September 4, 2017, issue of the *Oil and Gas Journal*, we were the third-largest U.S.-based oil and gas company in worldwide liquids production and reserves, and the fourth-largest U.S.-based oil and gas company in worldwide natural gas production and reserves in 2016. We deliver our production into the worldwide commodity markets. Principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; economic analysis in connection with portfolio management; and safely operating oil and gas producing properties.

## GENERAL

At the end of 2017, we held a total of 734 active patents in 47 countries worldwide, including 328 active U.S. patents. During 2017, we received 32 patents in the United States and 40 foreign patents. Our products and processes generated licensing revenues of $79 million in 2017. The overall profitability of any business segment is not dependent on any single patent, trademark, license, franchise or concession.

Company-sponsored research and development activities charged against earnings were $100 million, $116 million and $222 million in 2017, 2016 and 2015, respectively.

*Health, Safety and Environment*

Our Health, Safety and Environment (HSE) organization provides tools and support to our business units and staff groups to help them ensure world class health, safety and environmental performance. The framework through which we safely manage our operations, the HSE Management System Standard, emphasizes process safety, risk management, emergency preparedness and environmental performance, with an intense focus on process and occupational safety.  In support of the goal of zero incidents, HSE milestones and criteria are established annually to drive strong safety performance.  Progress toward these milestones and criteria are measured and reported.  HSE audits are conducted on business functions periodically, and improvement actions are established and tracked to completion.  We also have detailed processes in place to address sustainable development in our economic, environmental and social performance.  Our processes, related tools and requirements focus on water, biodiversity and climate change, as well as social and stakeholder issues.

The environmental information contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 61 through 64 under the captions "Environmental" and "Climate Change" is incorporated herein by reference.  It includes information on expensed and capitalized environmental costs for 2017 and those expected for 2018 and 2019.

**Website Access to SEC Reports**

Our internet website address is *www.conocophillips.com*.  Information contained on our internet website is not part of this report on Form 10-K.

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on our website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the U.S. Securities and Exchange Commission (SEC).  Alternatively, you may access these reports at the SEC's website at *www.sec.gov*.

## Item 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this Annual Report on Form 10-K. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

***Our operating results, our future rate of growth and the carrying value of our assets are exposed to the effects of changing commodity prices.***

Prices for crude oil, bitumen, natural gas, natural gas liquids and LNG can fluctuate widely. Globally, prices for crude oil, bitumen, natural gas, natural gas liquids and LNG have experienced significant declines from their historic levels during 2013 and 2014, with excess of supply relative to global demand leading to global inventory builds. Total average annual prices in 2017 for Brent crude oil, WTI crude oil, Henry Hub natural gas and our realized natural gas liquids all decreased by at least 30 percent when compared with 2014 despite having improved by at least 18 percent when compared with 2016. Given volatility in commodity price drivers and the business environment, price trends may not continue or reverse themselves.

Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil, bitumen, natural gas, natural gas liquids and LNG. The factors influencing these prices are beyond our control. Lower crude oil, bitumen, natural gas, natural gas liquids and LNG prices may have a material adverse effect on our revenues, operating income, cash flows and liquidity and on the amount of dividends we elect to declare and pay on our common stock. Lower prices may also limit the amount of reserves we can produce economically, adversely affecting our reserve replacement ratio and accelerating the reduction in our existing reserve levels as we continue production from upstream fields.

Significant reductions in crude oil, bitumen, natural gas, natural gas liquids and LNG prices could also require us to reduce our capital expenditures or impair the carrying value of our assets. In the past three years, we recognized several impairments, which are described in Note 8—Impairments and the "APLNG" section of Note 5—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements. If commodity prices remain low relative to their historic levels, and as we continue to optimize our investments and exercise capital flexibility, it is reasonably likely we will incur future impairments to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method and unproved properties. Although it is not reasonably practicable to quantify the impact of any future impairments at this time, our results of operations could be adversely affected as a result.

***Our ability to declare and pay dividends and repurchase shares is subject to certain considerations.***

Dividends are authorized and determined by our Board of Directors in its sole discretion and depend upon a number of factors, including:

- Cash available for distribution.
- Our results of operations and anticipated future results of operations.
- Our financial condition, especially in relation to the anticipated future capital needs of our properties.
- The level of reserves we establish for future capital expenditures.
- The level of distributions paid by comparable companies.
- Our operating expenses.
- Other factors our Board of Directors deems relevant.

We expect to continue to pay quarterly distributions to our stockholders; however, we bear all expenses incurred by our operations, and our funds generated by operations, after deducting these expenses, may not be sufficient to cover desired levels of distributions to our stockholders.

Additionally, our share repurchase program does not obligate us to acquire any specific number of shares. Any downward revision in our distribution or share repurchase program could have a material adverse effect on the market price of our common stock.

***We may need additional capital in the future, and it may not be available on acceptable terms.***

We have historically relied primarily upon cash generated by our operations to fund our operations and strategy, however we have also relied from time to time on access to the debt and equity capital markets for funding. There can be no assurance that additional debt or equity financing will be available in the future on acceptable terms, or at all. In addition, although we anticipate we will be able to repay our existing indebtedness when it matures or in accordance with our stated plans, there can be no assurance we will be able to do so. Our ability to obtain additional financing, or refinance our existing indebtedness when it matures or in accordance with our stated plans, will be subject to a number of factors, including market conditions, our operating performance, investor sentiment and our ability to incur additional debt in compliance with agreements governing our then-outstanding debt. If we are unable to generate sufficient funds from operations or raise additional capital, our growth could be impeded.

In addition, we are regularly evaluated by the major rating agencies based on a number of factors, including our financial strength and conditions affecting the oil and gas industry generally. For example, due to the significant decline in prices for crude oil, bitumen, natural gas, natural gas liquids and LNG in 2015, and the expectation that these prices could remain depressed, the major ratings agencies conducted a review of the oil and gas industry and downgraded our debt ratings and those of several companies operating in the industry in 2016. Any downgrade in our credit rating, could increase the cost associated with any additional indebtedness we incur.

***Our business may be adversely affected by deterioration in the credit quality of, or defaults under our contracts with, third parties with whom we do business.***

The operation of our business requires us to engage in transactions with numerous counterparties operating in a variety of industries, including other companies operating in the oil and gas industry. These counterparties may default on their obligations to us as a result of operational failures or a lack of liquidity, or for other reasons, including bankruptcy. Market speculation about the credit quality of these counterparties, or their ability to continue performing on their existing obligations, may also exacerbate any operational difficulties or liquidity issues they are experiencing, particularly as it relates to other companies in the oil and gas industry as a result of the volatility in commodity prices. Any default by any of our counterparties may result in our inability to perform obligations under agreements we have made with third parties or may otherwise adversely affect our business or results of operations. In addition, our rights against any of our counterparties as a result of a default may not be adequate to compensate us for the resulting harm caused or may not be enforceable at all in some circumstances.

***Unless we successfully add to our existing proved reserves, our future crude oil, bitumen, natural gas and natural gas liquids production will decline, resulting in an adverse impact to our business.***

The rate of production from upstream fields generally declines as reserves are depleted. Except to the extent that we conduct successful exploration and development activities, or, through engineering studies, optimize production performance or identify additional or secondary recovery reserves, our proved reserves will decline materially as we produce crude oil, bitumen, natural gas and natural gas liquids. Accordingly, to the extent we are unsuccessful in replacing the crude oil, bitumen, natural gas and natural gas liquids we produce with good prospects for future production, our business will experience reduced cash flows and results of operations. Any cash conservation efforts we may undertake as a result of commodity price declines may further limit our ability to replace depleted reserves.

***The exploration and production of oil and gas is a highly competitive industry.***

The exploration and production of crude oil, bitumen, natural gas and natural gas liquids is a highly competitive business. We compete with private, public and state-owned companies in all facets of the exploration and production business, including to locate and obtain new sources of supply and to produce oil, bitumen, natural gas and natural gas liquids in an efficient, cost-effective manner. Some of our competitors are larger and have greater resources than we do or may be willing to incur a higher level of risk than we are willing to incur to obtain potential sources of supply. If we are not successful in our competition for new reserves, our financial condition and results of operations may be adversely affected.

***Any material change in the factors and assumptions underlying our estimates of crude oil, bitumen, natural gas and natural gas liquids reserves could impair the quantity and value of those reserves.***

Our proved reserve information included in this annual report has been derived from engineering estimates prepared by our personnel. Reserve estimation is a process that involves estimating volumes to be recovered from underground accumulations of crude oil, bitumen, natural gas and natural gas liquids that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of reserves and future net cash flows based on the same available data. Any significant future price changes could have a material effect on the quantity and present value of our proved reserves. Any material changes in the factors and assumptions underlying our estimates of these items could result in a material negative impact to the volume of reserves reported or could cause us to incur impairment expenses on property associated with the production of those reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation. In addition to changes in the quantity and value of our proved reserves, the amount of crude oil, bitumen, natural gas and natural gas liquids that can be obtained from any proved reserve may ultimately be different from those estimated prior to extraction.

***We expect to continue to incur substantial capital expenditures and operating costs as a result of our compliance with existing and future environmental laws and regulations. Likewise, future environmental laws and regulations, such as limitations on greenhouse gas emissions, may impact or limit our current business plans and reduce demand for our products.***

Our businesses are subject to numerous laws and regulations relating to the protection of the environment. These laws and regulations continue to increase in both number and complexity and affect our operations with respect to, among other things:

- The discharge of pollutants into the environment.
- Emissions into the atmosphere, such as nitrogen oxides, sulfur dioxide, mercury and greenhouse gas emissions.
- Carbon taxes.
- The handling, use, storage, transportation, disposal and cleanup of hazardous materials and hazardous and nonhazardous wastes.
- The dismantlement, abandonment and restoration of our properties and facilities at the end of their useful lives.
- Exploration and production activities in certain areas, such as offshore environments, arctic fields, oil sands reservoirs and tight oil plays.

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our business, financial condition, results of operations and cash flows in future periods could be materially adversely affected.

Although our business operations are designed and operated to accommodate expected climatic conditions, to the extent there are significant changes in the Earth's climate, such as more severe or frequent weather conditions in the markets we serve or the areas where our assets reside, we could incur increased expenses, our operations could be materially impacted, and demand for our products could fall. Demand for our products may also be adversely affected by conservation plans and efforts undertaken in response to global climate change, including plans developed in connection with the Paris climate conference in December 2015. Many governments also provide, or may in the future provide, tax advantages and other subsidies to support the use and development of alternative energy technologies. Our operations and the demand for our products could be materially impacted by the development and adoption of these technologies.

***Domestic and worldwide political and economic developments could damage our operations and materially reduce our profitability and cash flows.***

Actions of the U.S., state, local and foreign governments, through tax and other legislation, executive order and commercial restrictions, including changes resulting from the implementation and interpretation of the Tax Cuts and Jobs Act, could reduce our operating profitability both in the United States and abroad. In certain locations, governments have imposed or proposed restrictions on our operations; special taxes or tax assessments; and payment transparency regulations that could require us to disclose competitively sensitive information or might cause us to violate non-disclosure laws of other countries. U.S. federal, state and local legislative and regulatory agencies' initiatives regarding the hydraulic fracturing process could result in operating restrictions or delays in the completion of our oil and gas wells.

The U.S. government can also prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries. Actions by host governments have affected operations significantly in the past, such as the expropriation of our oil assets by the Venezuelan government, and may continue to do so in the future. Changes in domestic and international regulations may affect our ability to obtain or maintain permits, including those necessary for drilling and development of wells in various locations.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 58 percent of our hydrocarbon production was derived from production outside the United States in 2017, and 45 percent of our proved reserves, as of December 31, 2017, was located outside the United States. We are subject to risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas, bitumen, natural gas liquids or LNG pricing and taxation, other political, economic or diplomatic developments, changing political conditions and international monetary fluctuations. In particular, some countries where we operate lack well-developed legal systems or have not adopted clear legal and regulatory frameworks for oil and gas exploration and production. This lack of legal certainty exposes our operations to increased risks, including increased difficulty in enforcing our agreements in those jurisdictions and increased risks of adverse actions by local government authorities, such as expropriations.

***Changes in governmental regulations may impose price controls and limitations on production of crude oil, bitumen, natural gas and natural gas liquids.***

Our operations are subject to extensive governmental regulations. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of crude oil, bitumen, natural gas and natural gas liquids wells below actual production capacity. Because legal requirements are frequently changed and subject to interpretation, we cannot predict the effect of these requirements.

***Our investments in joint ventures decrease our ability to manage risk.***

We conduct many of our operations through joint ventures in which we may share control with our joint venture partners. There is a risk our joint venture participants may at any time have economic, business or legal interests or goals that are inconsistent with those of the joint venture or us, or our joint venture partners may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone. Failure by us, or an entity in which we have a joint venture interest, to adequately manage the risks associated with any acquisitions or joint ventures could have a material adverse effect on the financial condition or results of operations of our joint ventures and, in turn, our business and operations.

***We may not be able to successfully complete any disposition we elect to pursue.***

From time to time, we may seek to divest portions of our business or investments that are not important to our ongoing strategic objectives. Any dispositions we undertake may involve numerous risks and uncertainties, any of which could adversely affect our results of operations or financial condition. In particular, we may not be able to successfully complete any disposition on a timeline or on terms acceptable to us, if at all, whether due to market conditions, regulatory challenges or other concerns. In addition, the reinvestment of capital from disposition proceeds may not ultimately yield investment returns in line with our internal or external expectations. Any dispositions we pursue may also result in disruption to other parts of our business, including through the diversion of resources and management attention from our ongoing business and other strategic matters, or through the disruption of relationships with our employees and key vendors. Further, in connection with any disposition, we may enter into transition services agreements or undertake indemnity or other obligations that may result in additional expenses for us.

As part of our disposition strategy, on May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction included 208 million Cenovus Energy common shares. We may not be able to liquidate the shares issued to us by Cenovus Energy at prices we deem acceptable, or at all.

***We do not insure against all potential losses; therefore, we could be harmed by unexpected liabilities and increased costs.***

We maintain insurance against many, but not all, potential losses or liabilities arising from operating risks. As such, our insurance coverage may not be sufficient to fully cover us against potential losses arising from such risks. Uninsured losses and liabilities arising from operating risks could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

***Our operations present hazards and risks that require significant and continuous oversight.***

The scope and nature of our operations present a variety of significant hazards and risks, including operational hazards and risks such as explosions, fires, crude oil spills, severe weather, geological events, labor disputes, terrorist attacks, sabotage, civil unrest or cyber attacks. Our operations may also be adversely affected by unavailability, interruptions or accidents involving services or infrastructure required to develop, produce, process or transport our production, such as contract labor, drilling rigs, pipelines, railcars, tankers, barges or other infrastructure. Our operations are subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. Activities in deepwater areas may pose incrementally greater risks because of complex subsurface conditions such as higher reservoir pressures, water depths and metocean conditions. All such hazards could result in loss of human life, significant property and equipment damage, environmental pollution, impairment of operations, substantial losses to us and damage to our reputation. Further, our business and operations may be disrupted if we do not respond, or are perceived not to respond, in an appropriate manner to any of these hazards and risks or any other major crisis or if we are unable to efficiently restore or replace affected operational components and capacity.

Our technologies, systems and networks may be subject to cybersecurity breaches. Although we have experienced occasional, actual or attempted breaches of our cybersecurity, none of these breaches has had a material effect on our business, operations or reputation. If our systems for protecting against cybersecurity risks prove to be insufficient, we could be adversely affected by having our business systems compromised, our proprietary information altered, lost or stolen, or our business operations disrupted. As cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information systems and related infrastructure security vulnerabilities.

## Item 1B. UNRESOLVED STAFF COMMENTS

None.

## Item 3. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the fourth quarter of 2017, as well as matters previously reported in our 2016 Form 10-K and our first-, second- and third-quarter 2017 Form 10-Qs that were not resolved prior to the fourth quarter of 2017. Material developments to the previously reported matters have been included in the descriptions below. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings were to be decided adversely to ConocoPhillips, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to SEC regulations.

On April 30, 2012, the separation of our downstream business was completed, creating two independent energy companies: ConocoPhillips and Phillips 66. In connection with the separation, we entered into an Indemnification and Release Agreement, which provides for cross-indemnities between Phillips 66 and us and established procedures for handling claims subject to indemnification and related matters, such as legal proceedings. We have included matters where we remain or have subsequently become a party to a proceeding relating to Phillips 66, in accordance with SEC regulations. We do not expect any of those matters to result in a net claim against us.

*Matters Previously Reported—Phillips 66*

In May 2012, the Illinois Attorney General's office filed and notified ConocoPhillips of a complaint with respect to operations at the Phillips 66 Wood River Refinery alleging violations of the Illinois groundwater standards and a third-party's hazardous waste permit. The complaint seeks as relief remediation of area groundwater; compliance with the hazardous waste permit; enhanced pipeline and tank integrity measures; additional spill reporting; and fines and penalties exceeding $100,000.

In October 2016, after Phillips 66 received a Notice of Intent to Sue from the Sierra Club, Phillips 66 entered into a voluntary settlement with the Illinois Environmental Protection Agency for alleged violations of wastewater requirements at the Wood River Refinery. The settlement involves certain capital projects and payment of $125,000. After the settlement was filed with the Court for final approval, the Sierra Club sought and was granted approval to intervene in the case. The settlement and a first modification have been entered by the Court, but the Sierra Club still seeks to reopen and challenge the settlement.

## Item 4. MINE SAFETY DISCLOSURES

Not applicable.

**EXECUTIVE OFFICERS OF THE REGISTRANT**

| Name | Position Held | Age* |
|---|---|---|
| Janet L. Carrig | Senior Vice President, Legal, General Counsel and Corporate Secretary | 60 |
| Ellen R. DeSanctis | Vice President, Investor Relations and Communications | 61 |
| Matt J. Fox | Executive Vice President, Strategy, Exploration and Technology | 57 |
| Alan J. Hirshberg | Executive Vice President, Production, Drilling and Projects | 56 |
| Ryan M. Lance | Chairman of the Board of Directors and Chief Executive Officer | 55 |
| Andrew D. Lundquist | Senior Vice President, Government Affairs | 57 |
| James D. McMorran | Vice President, Human Resources, Real Estate and Facilities Services | 60 |
| Glenda M. Schwarz | Vice President and Controller | 52 |
| Don E. Wallette, Jr. | Executive Vice President, Finance, Commercial and Chief Financial Officer | 59 |

**On February 15, 2018.*

There are no family relationships among any of the officers named above. Each officer of the company is elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and thereafter as appropriate. Each officer of the company holds office from the date of election until the first meeting of the directors held after the next Annual Meeting of Stockholders or until a successor is elected. The date of the next annual meeting is May 15, 2018. Set forth below is information about the executive officers.

**Janet L. Carrig** was appointed Senior Vice President, Legal, General Counsel and Corporate Secretary in 2007. On February 14, 2018, Ms. Carrig announced her decision to retire as Senior Vice President, Legal, General Counsel and Corporate Secretary. Ms. Carrig plans to remain in her current position until her successor is appointed.

**Ellen R. DeSanctis** was appointed Vice President, Investor Relations and Communications in May 2012. She was previously employed by Petrohawk Energy Corp. and served as Senior Vice President, Corporate Communications since 2010.

**Matt J. Fox** was appointed as Executive Vice President, Strategy, Exploration and Technology in April 2016. He previously served as the Executive Vice President, Exploration and Production, from 2012 to 2016. Prior to that, he was employed by Nexen, Inc. and served as Executive Vice President, International since 2010.

**Alan J. Hirshberg** was appointed Executive Vice President, Production, Drilling and Projects in April 2016. He previously served as Executive Vice President, Technology and Projects, from 2012 to 2016. Prior to that, he served as Senior Vice President, Planning and Strategy since 2010.

**Ryan M. Lance** was appointed Chairman of the Board of Directors and Chief Executive Officer in May 2012, having previously served as Senior Vice President, Exploration and Production—International since May 2009.

**Andrew D. Lundquist** was appointed Senior Vice President, Government Affairs in 2013. Prior to that, he served as managing partner of BlueWater Strategies LLC, since 2002.

**James D. McMorran** was appointed Vice President, Human Resources, Real Estate and Facilities Services in August 2015. Prior to that, he served as Manager, Compensation and Benefits, since 2004.

**Glenda M. Schwarz** was appointed Vice President and Controller in 2009.

**Don E. Wallette, Jr.** was appointed Executive Vice President, Finance, Commercial and Chief Financial Officer in April 2016. He previously served as Executive Vice President, Commercial, Business Development and Corporate Planning from 2012 to 2016. Prior to that, he served as President, Asia Pacific since 2010 and President, Russia/Caspian from 2006 to 2010.

## PART II

### Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

**Quarterly Common Stock Prices and Cash Dividends Per Share**

ConocoPhillips' common stock is traded on the New York Stock Exchange, under the symbol "COP."

| | | Stock Price | | |
|---|---|---|---|---|
| | | High | Low | Dividends |
| **2017** | | | | |
| First | **$** | **51.68** | **43.26** | **0.265** |
| Second | | **50.62** | **43.02** | **0.265** |
| Third | | **50.83** | **42.27** | **0.265** |
| Fourth | | **56.37** | **48.70** | **0.265** |
| 2016 | | | | |
| First | $ | 47.77 | 31.05 | 0.25 |
| Second | | 49.35 | 38.19 | 0.25 |
| Third | | 44.42 | 38.80 | 0.25 |
| Fourth | | 53.17 | 40.37 | 0.25 |

| | | |
|---|---|---|
| Closing Stock Price at December 31, 2017 | $ | 54.89 |
| Closing Stock Price at January 31, 2018 | $ | 58.46 |
| Number of Stockholders of Record at January 31, 2018* | | 46,680 |

**In determining the number of stockholders, we consider clearing agencies and security position listings as one stockholder for each agency listing.*

The declaration of dividends is subject to the discretion of our Board of Directors, and may be affected by various factors, including our future earnings, financial condition, capital requirements, levels of indebtedness, credit ratings and other considerations our Board of Directors deems relevant. Our Board of Directors has adopted a quarterly dividend declaration policy providing that the declaration of any dividends will be determined quarterly by the Board of Directors taking into account such factors as our business model, prevailing business conditions and our financial results and capital requirements, without a predetermined annual net income payout ratio.

On February 4, 2016, we announced that our Board of Directors approved a reduction in the quarterly dividend to $0.25 per share, compared with the previous quarterly dividend of $0.74 per share.

On January 31, 2017, we announced that our Board of Directors approved an increase in the quarterly dividend to $0.265 per share, compared with the previous quarterly dividend of $0.25 per share.

On February 1, 2018, we announced that our Board of Directors approved an increase in the quarterly dividend to $0.285 per share, compared with the previous quarterly dividend of $0.265 per share.

**Issuer Purchases of Equity Securities**

| | | | | Millions of Dollars |
|---|---|---|---|---|
| Period | Total Number of Shares Purchased* | Average Price Paid Per Share | Shares Purchased as Part of Publicly Announced Plans or Programs | Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs |
| October 1-31, 2017 | 6,678,455 | $ 49.94 | 6,678,455 | $ 3,496 |
| November 1-30, 2017 | 6,180,482 | 51.51 | 6,180,482 | 3,177 |
| December 1-31, 2017 | 5,773,183 | 52.52 | 5,773,183 | 2,874 |
| Total fourth-quarter 2017 | 18,632,120 | $ 51.26 | 18,632,120 | $ 2,874 |

**There were no repurchases of common stock from company employees in connection with the company's broad-based employee incentive plans.*

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock through 2019. On March 29, 2017, we announced plans to double our share repurchase program to $6 billion of common stock through 2019, with $3 billion allocated and purchased in 2017, and the remainder allocated evenly to 2018 and 2019. On February 1, 2018, we announced the acceleration of our previously stated 2018 share repurchases from $1.5 billion to $2.0 billion, with the remaining balance to be repurchased in 2019. Acquisitions for the share repurchase program are made at management's discretion, at prevailing prices, subject to market conditions and other factors. Repurchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan are held as treasury shares.

In addition to our previously announced share repurchase program above, we are currently planning to purchase up to an additional $1.5 billion of our common stock through 2020. Whether we undertake these additional repurchases is ultimately subject to numerous considerations, including Board authorization, market conditions and other factors. See Risk Factors "Our ability to declare and pay dividends and repurchase shares is subject to certain considerations."

**Stock Performance Graph**

The following graph shows the cumulative total shareholder return (TSR) for ConocoPhillips' common stock in each of the five years from December 31, 2012, to December 31, 2017. The graph also compares the cumulative total returns for the same five-year period with the S&P 500 Index and our performance peer group consisting of BP, Chevron, ExxonMobil, Royal Dutch Shell, Total, Anadarko, Apache, Marathon Oil Corporation, Devon and Occidental, weighted according to the respective peer's stock market capitalization at the beginning of each annual period. The comparison assumes $100 was invested on December 31, 2012, in ConocoPhillips stock, the S&P 500 Index and ConocoPhillips' peer group and assumes that all dividends were reinvested.

## Item 6. SELECTED FINANCIAL DATA

| | Millions of Dollars Except Per Share Amounts | | | | |
|---|---|---|---|---|---|
| | **2017** | 2016 | 2015 | 2014 | 2013 |
| Sales and other operating revenues | $ **29,106** | 23,693 | 29,564 | 52,524 | 54,413 |
| Income (loss) from continuing operations | **(793)** | (3,559) | (4,371) | 5,807 | 8,037 |
| Per common share | | | | | |
| Basic | **(0.70)** | (2.91) | (3.58) | 4.63 | 6.47 |
| Diluted | **(0.70)** | (2.91) | (3.58) | 4.60 | 6.43 |
| Income from discontinued operations | - | - | - | 1,131 | 1,178 |
| Net income (loss) | **(793)** | (3,559) | (4,371) | 6,938 | 9,215 |
| Net income (loss) attributable to ConocoPhillips | **(855)** | (3,615) | (4,428) | 6,869 | 9,156 |
| Per common share | | | | | |
| Basic | **(0.70)** | (2.91) | (3.58) | 5.54 | 7.43 |
| Diluted | **(0.70)** | (2.91) | (3.58) | 5.51 | 7.38 |
| Total assets | **73,362** | 89,772 | 97,484 | 116,539 | 118,057 |
| Long-term debt | **17,128** | 26,186 | 23,453 | 22,383 | 21,073 |
| Joint venture acquisition obligation— | | | | | |
| Cash dividends declared per common share | **1.06** | 1.00 | 2.94 | 2.84 | 2.70 |

Net income (loss) and net income (loss) attributable to ConocoPhillips from 2013 to 2014 includes income from discontinued operations as a result of the sale of our interest in Kashagan, and the sales of our Algeria and Nigeria businesses. These factors impact the comparability of this information.

See Management's Discussion and Analysis of Financial Condition and Results of Operations and the Notes to Consolidated Financial Statements for a discussion of factors that will enhance an understanding of this data.

## Item 7. 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 financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. 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 the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 70.*

*The terms "earnings" and "loss" as used in Management's Discussion and Analysis refer to net income (loss) attributable to ConocoPhillips.*

### BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

ConocoPhillips is the world's largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. Headquartered in Houston, Texas, we have operations and activities in 17 countries. Our diverse portfolio primarily includes resource-rich North American tight oil and oil sands assets in Canada; lower-risk conventional assets in North America, Europe, Asia and Australia; several liquefied natural gas (LNG) developments; and an inventory of global conventional and unconventional exploration prospects. At December 31, 2017, we employed approximately 11,400 people worldwide and had total assets of $73 billion. Our common stock is listed on the New York Stock Exchange under the symbol "COP."

#### Overview

The global oil market is rebalancing. Crude oil prices improved in 2017, particularly during the latter half of the year; however, we believe prices are likely to remain cyclical in the future. In 2016, we updated our value proposition to position the company for long-term success, given our expectations. Our value proposition principles, namely to maintain financial strength, grow our distributions and pursue disciplined growth, remain essentially unchanged. However, we took steps to improve our competitiveness and resilience by establishing clear priorities for cash allocation.

In order, the cash allocation priorities are: invest capital at a level that maintains flat production volumes and pays our existing dividend; grow our existing dividend; reduce debt to a level we believe is sufficient to maintain a strong investment grade rating through price cycles; repurchase shares to provide value to our shareholders; and strategically invest capital to grow our cash from operations.

In 2017, we took significant actions that allowed us to make substantial progress on our stated priorities. We believe that our commitment to our value proposition, as evidenced by the results discussed below, position the company for success in an environment of price uncertainty and ongoing volatility.

## Key Operating and Financial Summary

Significant items during 2017 included the following:

- Achieved full-year production excluding Libya of 1,356 thousand barrels of oil equivalent per day (MBOED); underlying production excluding the impact of closed and planned dispositions grew 19 percent on a production per debt-adjusted share basis and 3 percent overall.
- Cash provided by operating activities exceeded capital expenditures by $2.5 billion, and exceeded capital expenditures and dividends by $1.2 billion.
- Paid down $7.6 billion of balance sheet debt, ending the year with debt of $19.7 billion.
- Generated approximately $16 billion from asset dispositions.
- Announced year-end proved reserves of 5.0 billion barrels of oil equivalent (BOE).
- Repurchased $3 billion of shares; reduced ending share count by 5 percent year over year.
- Reached settlement on Ecuador arbitration for $337 million.

Operationally, we continue to focus on safely executing our capital program and remaining attentive to our costs. Production excluding Libya was 1,356 MBOED in 2017 compared with 1,567 MBOED in 2016. Our underlying production, which excludes the full-year impact of closed and planned dispositions of 191 MBOED in 2017 and 434 MBOED in 2016 and Libya, increased 32 MBOED, or 3 percent year over year. Underlying production on a per debt-adjusted share basis grew by 19 percent compared to 2016. Production per debt-adjusted share is calculated on an underlying production basis using ending period debt divided by ending share price plus ending shares outstanding. We believe production per debt-adjusted share is useful to investors as it provides a consistent view of production on a total equity basis by converting debt to equity and allows for comparisons across peer companies.

We accomplished several strategic milestones in 2017, including progressing our efforts to optimize our portfolio. Our asset dispositions are in line with our strategy, announced in November 2016, to focus on low cost-of-supply projects in our portfolio that strategically fit our development plans. We generated approximately $16 billion in total consideration from the disposition of certain noncore assets which were directed to our stated cash priorities and general corporate purposes. For additional information on our dispositions, see Note 4—Assets Held for Sale, Sold or Acquired in the Notes to Consolidated Financial Statements.

In 2017, we reduced debt by $7.6 billion to $19.7 billion at year-end and repurchased 64 million shares of our common stock totaling $3 billion. Consistent with our commitment to grow our distributions, in the first quarter of 2017, we increased our quarterly dividend by 6 percent to $0.265 per share. We are managing our business to optimize and deliver on our value propositions and cash priorities in a demanding business environment.

## Business Environment

After elevated levels of volatility in 2016, global market fundamentals trended towards a firmer balance in 2017. Crude oil prices improved in 2017 as a result of slower growth in global oil production, strong global oil demand and lower global inventory levels.

The energy industry has periodically experienced this type of extreme volatility due to fluctuating supply-and-demand conditions. Commodity prices are the most significant factor impacting our profitability and related reinvestment of operating cash flows into our business. Our strategy is to create value through price cycles by delivering on the disciplined financial and operational priorities that underpin our value proposition.

*Priorities*

The priorities we believe will drive our success through the price cycles include:

- Focus on financial returns. This is a core aspect of our value proposition. Our goal is to achieve strong financial returns by controlling our costs, exercising capital discipline and continually optimizing our portfolio.

  - Control costs and expenses. Controlling operating and overhead costs, without compromising safety and environmental stewardship, is a high priority. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Managing operating and overhead costs is critical to maintaining a competitive position in our industry, particularly in a low commodity price environment. The ability to control our operating and overhead costs impacts our ability to deliver strong cash from operations. In 2017, including asset disposition impacts, we reduced our production and operating expenses by 9 percent as compared to 2016.

  - Maintain capital discipline. We participate in a commodity price-driven and capital-intensive industry, with varying lead times from when an investment decision is made to the time an asset is operational and generates cash flow. As a result, we must invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, and construct pipelines and LNG facilities. Given our view of greater price volatility, we have shifted our capital allocation to focus on shorter cycle time, low cost-of-supply, unconventional programs in our resource base. Our cash allocation priorities call for the investment of sufficient capital to maintain production and pay the existing dividend. Additional allocations of capital toward growth projects will be dependent on satisfaction of other financial priorities. We use a disciplined approach, focused on value maximization and cash flow expansion, to set our capital plans.

    In November 2017, we announced a 2018 capital budget of $5.5 billion, including $3.5 billion of sustaining capital and $2 billion in accretive, short-cycle unconventional programs, future major projects and exploration activities.

  - Optimize our portfolio. We continue to optimize our asset portfolio by focusing on low cost-of-supply assets which strategically fit our development plans. In 2017, we generated approximately $16 billion in total consideration from dispositions of certain noncore assets in our portfolio, including our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets; our interests in the San Juan Basin; and our interest in the Panhandle assets. We will continue to evaluate our assets to determine whether they fit our strategic direction and will optimize the portfolio as necessary, directing our capital investments to areas that align with our objectives.

- Maintain financial strength. We believe financial strength is critical in a cyclical business such as ours. In 2017, using proceeds from asset dispositions and cash flow from operations, we reduced our debt by $7.6 billion to $19.7 billion at year-end. On a longer-term basis, in November 2017, we announced our plan to reduce debt to $15 billion by year-end 2019, a significant acceleration from the previously stated expectation of $20 billion in the same timeframe. We expect to retire outstanding debt as it matures and exercise flexibility in paying down our other debt instruments.

- Return capital to shareholders. In 2017, we paid dividends on our common stock of $1.3 billion and repurchased $3 billion of our common stock. We believe in delivering value to our shareholders through the price cycles. As a result, we set a priority to increase our dividend rate annually and purchase up to approximately $3 billion of our common stock evenly from 2018 through 2019.

On February 1, 2018, we announced that our Board of Directors approved an increase in the quarterly dividend to $0.285 per share, compared with the previous quarterly dividend of $0.265 per share. Additionally, we announced the acceleration of our previously stated 2018 share repurchases from $1.5 billion to $2.0 billion.

In addition to our previously announced share repurchase program above, we are currently planning to purchase up to an additional $1.5 billion of our common stock through 2020. Whether we undertake these additional repurchases is ultimately subject to numerous considerations, including Board authorization, market conditions and other factors. See Risk Factors "Our ability to declare and pay dividends and repurchase shares is subject to certain considerations."

- Maintain a relentless focus on safety and environmental stewardship. Safety and environmental stewardship, including the operating integrity of our assets, remain our highest priorities, and we are committed to protecting the health and safety of everyone who has a role in our operations and the communities in which we operate. We strive to conduct our business with respect and care for both the local and global environment and systematically manage risk to drive sustainable business growth. Our sustainability efforts in 2017 focused on implementing our action plans for climate change, biodiversity, water and human rights, as well as revamping public reporting to be more informative, searchable and responsive to common questions. To demonstrate our commitment to sustainability and environmental stewardship, on November 2017, we announced our intention to target a 5 to 15 percent reduction in our greenhouse gas emission intensity by 2030. We are committed to building a learning organization using human performance principles as we relentlessly pursue improved Health, Safety and Environment and operational performance.

- Add to our proved reserve base. We primarily add to our proved reserve base in two ways:

    - Successful exploration, exploitation and development of new and existing fields.
    - Application of new technologies and processes to improve recovery from existing fields.

  Proved reserve estimates require economic production based on historical 12-month, first-of-month, average prices and current costs. Therefore, our proved reserves generally increase as prices rise and decrease as prices decline. Asset dispositions in 2017 reduced our reported year-end proved reserves, but were partly offset by increased commodity prices. In 2017, our reserve replacement, which included a reduction of 1.9 billion BOE from dispositions, was negative 168 percent. Our organic reserve replacement, which excludes the impact of sales and purchases, was 200 percent in 2017. In the five years ended December 31, 2017, our reserve replacement was negative 24 percent, reflecting the impact of asset dispositions and lower prices.

  Access to additional resources may become increasingly difficult as commodity prices can make projects uneconomic or unattractive. In addition, prohibition of direct investment in some nations, national fiscal terms, political instability, competition from national oil companies, and lack of access to high-potential areas due to environmental or other regulation may negatively impact our ability to increase our reserve base. As such, the timing and level at which we add to our reserve base may, or may not, allow us to replace our production over subsequent years. Additionally, as we continue cash conservation efforts, our reserve replacement efforts could be delayed thus limiting our ability to replace depleted reserves.

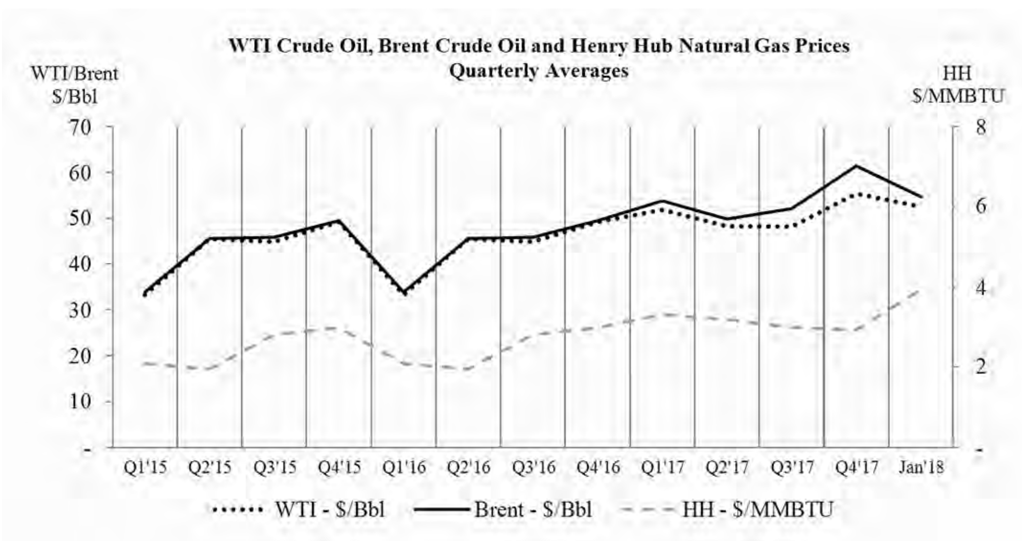
- Apply technical capability. We leverage our knowledge and technology to create value and safely deliver on our plans. Technical strength is part of our heritage, and we are evolving our technical approach to optimally apply best practices. Companywide, we continue to evaluate potential solutions to leverage knowledge of technological successes across our operations. Such innovations enable us to economically convert additional resources to reserves, achieve greater operating efficiencies and reduce our environmental impact.

- Develop and retain a talented work force. We strive to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics. To this end, we offer university internships across multiple disciplines to attract the best talent and, as needed, recruit experienced hires to maintain a broad range of skills and experience. We promote continued learning, development and technical training through structured development programs designed to enhance the technical and functional skills of our employees.

*Other Factors Affecting Profitability*

Other significant factors that can affect our profitability include:

- Energy commodity prices. Our earnings and operating cash flows generally correlate with industry price levels for crude oil and natural gas. Industry price levels are subject to factors external to the company and over which we have no control, including but not limited to global economic health, supply disruptions or fears thereof caused by civil unrest or military conflicts, actions taken by Organization of Petroleum Exporting Countries (OPEC), environmental laws, tax regulations, governmental policies and weather-related disruptions. The following graph depicts the average benchmark prices for West Texas Intermediate (WTI) crude oil, Dated Brent crude oil and U.S. Henry Hub natural gas:




Brent crude oil prices averaged $61.39 per barrel in the fourth quarter of 2017, an increase of 24 percent compared with $49.46 per barrel in the fourth quarter of 2016. Similarly, WTI crude oil prices increased 13 percent from $49.18 per barrel in the fourth quarter of 2016 to $55.35 per barrel in the same period of 2017. Global oil prices began to improve at the end of 2016 and continued trending upward in response to stronger global demand and slower production growth.

Henry Hub natural gas prices averaged $2.93 per million British thermal units (MMBTU) in the fourth quarter of 2017, a decrease of 2 percent compared with $2.98 per MMBTU in the fourth quarter of 2016. However, on an annual basis, Henry Hub natural gas prices improved 26 percent from $2.46 per MMBTU in 2016, to $3.11 per MMBTU in 2017. The price improvement was as a result of growth in domestic demand, increased exports and lower U.S. inventories.

Our realized natural gas liquids prices averaged $32.79 per barrel in the fourth quarter of 2017, an increase of 50 percent compared with $21.82 per barrel in the same quarter of 2016.

Improving global crude oil prices resulted in the Western Canada Select benchmark price experiencing a 33 percent increase, from $29.36 per barrel in 2016 to $38.92 per barrel in 2017. The WCS benchmark price improvement, coupled with changes in costs per barrel resulting from the disposition of our interest in the FCCL Partnership, caused our realized bitumen price to increase relative to 2016. Our realized bitumen price was $22.66 per barrel in 2017, an increase of 48 percent compared with $15.27 per barrel in the same period of 2016.

Our worldwide annual average realized price was $46.10 per barrel of oil equivalent (BOE) in the fourth quarter of 2017, an increase of 40 percent compared with $32.93 per BOE in the fourth quarter of 2016. Similarly, our worldwide annual average realized price was $39.19 per BOE in 2017, an increase of 38 percent compared with $28.35 per BOE in 2016, reflecting higher average realized prices across all commodities.

North America's energy landscape has been transformed from resource scarcity to an abundance of supply. In recent years, the use of hydraulic fracturing and horizontal drilling in tight oil formations has led to increased industry actual and forecasted crude oil and natural gas production in the United States. Although providing significant short- and long-term growth opportunities for our company, the increased abundance of crude oil and natural gas due to development of tight oil plays could also have adverse financial implications to us, including: an extended period of low commodity prices; production curtailments; delay of plans to develop areas such as unconventional fields or Alaska North Slope natural gas fields; and underutilization of LNG regasification facilities. Should one or more of these events occur, our revenues would be reduced and additional asset impairments might be possible.

- Impairments. As mentioned earlier, we participate in a capital-intensive industry. At times, our properties, plants and equipment and investments become impaired when, for example, commodity prices decline significantly for long periods of time, our reserve estimates are revised downward, or a decision to dispose of an asset leads to a write-down to its fair value. We may also invest large amounts of money in exploration which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. In 2017, we recorded before-tax impairments of $6,601 million for proved properties and $136 million for unproved properties. As we optimize our assets in the future, it is reasonably possible we may incur future losses upon sale or impairment charges to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method, and unproved properties. For additional information on our impairments in 2017, 2016 and 2015, see Note 8—Impairments, in the Notes to Consolidated Financial Statements.

- Effective tax rate. Our operations are located in countries with different tax rates and fiscal structures. Accordingly, even in a stable commodity price and fiscal/regulatory environment, our overall effective tax rate can vary significantly between periods based on the "mix" of before-tax earnings within our global operations. Recent changes in the U.S. corporate income tax law, further discussed below, additionally impacted our effective tax rate in 2017.

- Fiscal and regulatory environment. Our operations can be affected by changing economic, regulatory and political environments in the various countries in which we operate, including the United States. Civil unrest or strained relationships with governments may impact our operations or investments. These changing environments have generally negatively impacted our results of operations, and further changes to government fiscal take could have a negative impact on future operations. Our assets in Venezuela were expropriated in 2007. Our production operations in Libya and related oil exports were suspended or significantly curtailed from July 2013 to October 2016 due to the closure of the Es Sider crude oil export terminal, and they were also suspended in 2011 during Libya's period of civil unrest. In 2016, the United Kingdom government enacted tax legislation which reduced our U.K. corporate tax rate by 10 percent.

  On December 22, 2017, the Tax Cuts and Jobs Act ("Tax Legislation") was enacted, significantly revising the U.S. corporate income tax law by, among other things, lowering the corporate income tax rate from 35 percent to 21 percent, implementing a territorial tax system and imposing a one-time deemed repatriation tax on untaxed accumulated foreign earnings. We recognized a provisional, noncash tax benefit of $852 million, which is included as a component of our 2017 income tax expense, primarily related to the revaluation of deferred taxes at the lower 21 percent federal statutory rate. We did not incur nor expect to incur a tax cost related to the one-time repatriation of accumulated foreign earnings. While we anticipate the Tax Legislation will provide a positive impact to our U.S. operations in the future primarily because of the reduced U.S. federal statutory rate, we do not expect to realize cash tax benefits from the Tax Legislation until we move into a U.S. tax paying position. The ultimate impact of the Tax Legislation may differ from our current expectations, due to, among other things, changes in interpretations and assumptions the company has made or additional regulatory or accounting guidance that may be issued with respect to the Tax Legislation. For additional information, see Note 18—Income Taxes, in the Notes to Consolidated Financial Statements.

Our management carefully considers the fiscal and regulatory environment when evaluating projects or determining the levels and locations of our activity.

**Outlook**

Full-year 2018 production is expected to be 1,195 to 1,235 MBOED. This results in approximately 5 percent growth compared with full-year 2017 underlying production, which excludes the impact of closed and planned dispositions of 191 MBOED. First-quarter 2018 production is expected to be 1,180 to 1,220 MBOED. Production guidance for 2018 excludes Libya.

**Operating Segments**

We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, premiums incurred on the early retirement of debt, corporate overhead, certain technology activities, as well as licensing revenues received.

Our key performance indicators, shown in the statistical tables provided at the beginning of the operating segment sections that follow, reflect results from our operations, including commodity prices and production.

## RESULTS OF OPERATIONS

### Consolidated Results

A summary of the company's net loss attributable to ConocoPhillips by business segment follows:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| Years Ended December 31 | | **2017** | 2016 | 2015 |
| Alaska | $ | **1,466** | 319 | 4 |
| Lower 48 | | **(2,371)** | (2,257) | (1,932) |
| Canada | | **2,564** | (935) | (1,044) |
| Europe and North Africa | | **553** | 394 | 409 |
| Asia Pacific and Middle East | | **(1,098)** | 209 | (463) |
| Other International | | **167** | (16) | (593) |
| Corporate and Other | | **(2,136)** | (1,329) | (809) |
| Net loss attributable to ConocoPhillips | $ | **(855)** | (3,615) | (4,428) |

*2017 vs. 2016*

Loss attributable to ConocoPhillips decreased $2,760 million in 2017. The decrease was mainly due to:

- Higher commodity prices.
- Lower depreciation, depletion and amortization (DD&A) expense, mainly due to lower unit-of-production rates from reserve revisions and disposition impacts.
- Higher gains on dispositions, primarily due to a $1.6 billion after-tax gain in 2017 on the sale of certain Canadian assets.
- Recognition of deferred tax benefits totaling $996 million, primarily related to the disposition of certain Canadian assets.
- Recognition of deferred tax benefits totaling $852 million related to the Tax Legislation enacted on December 22, 2017.
- Improved equity earnings, mainly due to higher realized prices, lower DD&A from asset disposition impacts, and the absence of a 2016 deferred tax charge of $174 million resulting from the change of the tax functional currency for APLNG to the U.S. dollar. These increases were partly offset by lower volumes from the disposition of our interest in the FCCL Partnership.
- Lower exploration expenses mainly due to reduced leasehold impairment expense, dry hole costs and other exploration expenses.
- A $337 million award from an arbitration settlement with The Republic of Ecuador.
- Lower production and operating expenses, primarily due to asset disposition impacts.
- Lower net interest expense, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and reduced debt.

The reduction in loss was partly offset by:

- Higher proved property and equity investment impairments, including a combined $2.5 billion after-tax impairment related to the sale of our interests in the San Juan Basin and the ongoing marketing of the Barnett, as well as a $2.4 billion before- and after-tax impairment of our equity investment in APLNG.
- Lower volumes primarily due to asset dispositions in our Lower 48, Asia Pacific and Middle East, and Canada segments, as well as normal field decline.
- A $238 million after-tax charge associated with our early retirements of debt in 2017.

*2016 vs. 2015*

Loss attributable to ConocoPhillips decreased $813 million in 2016. The decrease was mainly due to:

- Lower exploration expenses. Exploration expenses decreased mainly due to reduced leasehold impairment expense and dry hole costs.
- Lower proved property and equity investment impairments, including the absence of a $1.5 billion before- and after-tax impairment of our equity investment in APLNG in 2015.
- Lower production and operating expenses.
- A $161 million net deferred tax benefit resulting from a reduction in the U.K. tax rate, which was enacted in September 2016 and effective January 1, 2016.
- The absence of a $129 million deferred tax charge from increased corporate tax rates in Canada in 2015.

The decrease in loss was partly offset by:

- Lower commodity prices.
- The absence of a $555 million net deferred tax benefit resulting from a change in the U.K. tax rate in 2015.
- Lower crude oil, natural gas liquids, and gas sales volumes.
- Lower equity earnings, primarily driven by increased DD&A expense, as well as a 2016 deferred tax charge of $174 million resulting from the change of the tax functional currency for APLNG to U.S. dollar.
- Higher interest and debt expense.
- Lower gain on dispositions, mainly due to the absence of a $368 million after-tax gain on the disposition of certain properties in our Lower 48 segment.

**Income Statement Analysis**

*2017 vs. 2016*

Sales and other operating revenues increased 23 percent in 2017, mainly due to higher realized prices across all commodities, partly offset by lower sales volumes, primarily in our Lower 48, Asia Pacific and Middle East, and Canada segments as a result of dispositions.

Equity in earnings of affiliates increased $720 million in 2017. The increase in equity earnings was primarily due to higher realized commodity prices at QG3, APLNG and FCCL; the absence of a 2016 deferred tax charge of $174 million resulting from a tax functional currency change; and reduced costs mainly from the disposition of our interest in the FCCL Partnership. The increase in earnings was partly offset by lower volumes as a result of our FCCL disposition.

Gain on dispositions increased 505 percent in 2017. The increase was primarily due to a before-tax gain of $2.1 billion on the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets. For additional information on gains on dispositions, see Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements.

Other income increased 107 percent in 2017, mainly due to a $337 million before- and after-tax International Centre for Settlement of Investment Disputes (ICSID) arbitration award from The Republic of Ecuador. The increase was partly offset by the absence of a gain of $88 million from our receipt of mineral properties and active leases from the Greater Northern Iron Ore Properties Trust and a $76 million before-tax damage claim settlement, both in our Lower 48 segment in 2016.

Purchased commodities increased 25 percent in 2017, mainly due to higher commodity prices and increased activity.

Selling, general and administrative (SG&A) expenses decreased 22 percent in 2017, primarily due to reduced restructuring expenses, lower headcount and reduced activity.

Exploration expenses decreased 51 percent in 2017, primarily as a result of lower leasehold impairment expense, dry hole costs and other exploration expenses.

Leasehold impairment expense was reduced mainly due to the absence of 2016 before-tax charges of $203 million for our Gibson and Tiber leaseholds. The expense was further reduced by the absence of before-tax charges of $95 million for our Melmar leasehold and $79 million for various Gulf of Mexico leases after completion of marketing efforts. The reduction was partly offset by a before-tax charge of $51 million for Shenandoah in deepwater Gulf of Mexico and a before-tax charge of $38 million for certain mineral assets in our Lower 48 segment, both in 2017.

Dry hole costs were reduced primarily due to the absence of 2016 before-tax charges in deepwater Gulf of Mexico of $249 million for our Gibson and Tiber wells, and $128 million for our Melmar well. The absence of a $256 million before-tax charge in 2016 for two dry holes in Nova Scotia further reduced costs. The reduction in dry hole costs was partly offset by 2017 before-tax charges of $288 million for multiple wells in Shenandoah, including wells previously suspended, and $63 million for several wells in the Powder River Basin.

Other exploration expenses were reduced mainly due to the absence of a $146 million before-tax expense in 2016 related to the cancellation of our final Gulf of Mexico deepwater drillship contract, as well as lower rig stacking costs in Angola. The decrease in expense was partly offset by a $43 million net before-tax charge in 2017 for the settlement of our drilling rig contract in Angola.

For additional information on leasehold impairments and other exploration expenses, see Note 7—Suspended Wells and Other Exploration Expenses, and Note 8—Impairments, in the Notes to Consolidated Financial Statements.

DD&A decreased 24 percent in 2017, mainly due to lower unit-of-production rates from reserve revisions and disposition impacts in our Canada and Lower 48 segments.

Impairments increased $6,462 million in 2017. For additional information, see Note 8—Impairments, in the Notes to Consolidated Financial Statements.

Interest and debt expense decreased 12 percent in 2017, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and lower interest on debt.

Other expense included before-tax charges of $302 million in 2017 for premiums on early debt retirements.

See Note 18—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax benefit and effective tax rate.

*2016 vs. 2015*

Sales and other operating revenues decreased 20 percent in 2016, mainly as a result of lower prices across all commodities. Additionally, sales and other operating revenues decreased due to lower natural gas, crude oil and natural gas liquids sales volumes, mainly from dispositions and field decline, partly offset by increased bitumen sales volumes.

Equity in earnings of affiliates decreased 92 percent in 2016. The decrease was primarily due to lower commodity prices, increased DD&A mainly from Trains 1 and 2 being placed in service at APLNG, and a 2016 deferred tax charge of $174 million resulting from a tax functional currency change. The decrease in earnings was partly offset by higher sales volumes at APLNG and FCCL Partnership, as well as lower production taxes at QG3.

Gain on dispositions decreased 39 percent in 2016. The decrease resulted from the absence of a $583 million before-tax gain in 2015 from the sales of producing properties in East Texas and North Louisiana, South Texas, and a certain pipeline and gathering assets in South Texas, as well as a $26 million before-tax loss on the sale of our interest in the Block B PSC in Indonesia in 2016. The decrease was partly offset by the absence of a $149 million before-tax loss on the disposition of noncore assets in western Canada in the fourth quarter of 2015; and gains on the 2016 dispositions of ConocoPhillips Senegal B.V., the entity that held our interests in three exploration blocks offshore Senegal, the Alaska Beluga River Unit natural gas field, and noncore assets in the Lower 48. For additional information on gains on dispositions, see Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements.

Other income increased 104 percent in 2016, mainly due to a gain of $88 million from our receipt of mineral properties and active leases from the Greater Northern Iron Ore Properties Trust in the fourth quarter of 2016. Other income was further increased $76 million before-tax for a damage claim settlement in our Lower 48 segment.

Purchased commodities decreased 20 percent in 2016, mainly due to lower natural gas prices.

Production and operating expenses decreased 19 percent in 2016, mainly due to lower operating expense activity, reduced headcount and dispositions of noncore assets, as well as favorable foreign currency impacts.

SG&A expenses decreased 24 percent in 2016, primarily due to reduced restructuring expenses, lower headcount and reduced activity. The decrease was partly offset by increases from market impacts on certain compensation programs.

Exploration expenses decreased 54 percent in 2016, primarily as a result of lower leasehold impairment expense, dry hole costs, and other exploration expenses.

Leasehold impairment expense was reduced, mainly due to the absence of 2015 before-tax charges of $575 million for our Chukchi Sea leasehold and capitalized interest; $493 million for Angola Blocks 36 and 37; and $447 million for certain Gulf of Mexico leases, partly offset by 2016 impairments of our Melmar, Gibson, Tiber and other Gulf of Mexico leaseholds.

Dry hole costs were reduced due to the absence of before-tax charges of $1,141 million in 2015, mainly from wells in deepwater Gulf of Mexico, Horn River and Northwest Territories in Canada, Angola Blocks 36 and 37, and Malaysia. The reduction in costs was partly offset by before-tax charges in 2016, including $434 million from several wells in deepwater Gulf of Mexico and $256 million for two wells in Nova Scotia.

Other exploration expenses were reduced mainly due to the absence of a $335 million before-tax charge in 2015 related to the termination of our Ensco Gulf of Mexico deepwater drillship contract, partly offset by before-tax rig cancellation charges and third-party costs of $146 million for our final Gulf of Mexico deepwater drillship contract in 2016.

For additional information on leasehold impairments and other exploration expenses, see Note 7—Suspended Wells and Other Exploration Expenses, and Note 8—Impairments, in the Notes to Consolidated Financial Statements.

Impairments decreased 94 percent in 2016. For additional information, see Note 8—Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes decreased 18 percent in 2016, primarily as a result of lower production taxes, mainly in our Alaska and Lower 48 segments, given reduced commodity prices and the absence of the impact of a transportation cost ruling by the Federal Energy Regulatory Commission in the fourth quarter of 2015 in Alaska. Taxes other than income taxes were additionally decreased due to lower property taxes in 2016 in our Alaska and Lower 48 segments.

Interest and debt expense increased 35 percent in 2016, primarily due to lower capitalized interest on projects and increased debt.

See Note 18—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax benefit and effective tax rate.

**Summary Operating Statistics**

| | | 2017 | 2016 | 2015 |
|---|---|---|---|---|
| **Average Net Production** | | | | |
| Crude oil (MBD)* | | **599** | 598 | 605 |
| Natural gas liquids (MBD) | | **111** | 145 | 156 |
| Bitumen (MBD) | | **122** | 183 | 151 |
| Natural gas (MMCFD)** | | **3,270** | 3,857 | 4,060 |
| **Total Production** (MBOED)*** | | **1,377** | 1,569 | 1,589 |
| | | Dollars Per Unit | | |
| **Average Sales Prices** | | | | |
| Crude oil (per barrel) | **$** | **51.96** | 40.86 | 48.26 |
| Natural gas liquids (per barrel) | | **25.22** | 16.68 | 17.79 |
| Bitumen (per barrel) | | **22.66** | 15.27 | 18.72 |
| Natural gas (per thousand cubic feet) | | **4.07** | 3.00 | 3.96 |
| | | Millions of Dollars | | |
| **Worldwide Exploration Expenses** | | | | |
| General and administrative; geological and geophysical, lease rental, and other | **$** | **372** | 731 | 1,127 |
| Leasehold impairment | | **136** | 466 | 1,924 |
| Dry holes | | **430** | 718 | 1,141 |
| | **$** | **938** | 1,915 | 4,192 |

**Thousands of barrels per day.*
***Millions of cubic feet per day. Represents quantities available for sale and excludes gas equivalent of natural gas liquids included above.*
****Thousands of barrels of oil equivalent per day.*

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2017, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

Total production, including Libya, of 1,377 MBOED decreased 12 percent in 2017 compared with 2016. The decrease in total average production primarily resulted from noncore asset dispositions, including our Canada and San Juan transactions in 2017 and the sale of our interest in the Block B production sharing contract (PSC) in Indonesia in 2016, and normal field decline. The decrease in production was partly offset by production from major developments, including tight oil plays in the Lower 48; Malikai and the Kebabangan gas field in Malaysia; Surmont in Canada; and APLNG in Australia. Improved drilling and well performance in Alaska, Norway and China also partly offset the decrease in production. Excluding Libya, our 2017 production was 1,356 MBOED. Adjusted for the impact of closed and planned dispositions of 191 MBOED in 2017 and 434 MBOED in 2016 and Libya, our underlying production increased 32 MBOED, or 3 percent, compared with 2016.

In 2016, total production, including Libya, of 1,569 MBOED decreased 1 percent compared with 2015. The decrease in total average production primarily resulted from normal field decline and the loss of 72 MBOED mainly attributable to the 2015 dispositions of several noncore assets in the Lower 48, western Canada and the sale of our interest in the Polar Lights Company in Russia. The decrease in production was partly offset by additional production from major developments, including tight oil plays in the Lower 48; APLNG in Australia; the Western North Slope in Alaska; the Kebabangan gas field in Malaysia; and the Greater Ekofisk Area in Norway. Improved drilling and well performance in Canada, Norway, the Lower 48, and China, as well as lower unplanned downtime in the Lower 48 also partly offset the decrease in production. Assets sold in 2016 produced 27 MBOED and 36 MBOED in 2016 and 2015, respectively.

**Alaska**

| | | **2017** | 2016 | 2015 |
|---|---|---|---|---|
| **Net Income Attributable to ConocoPhillips** (millions of dollars) | $ | **1,466** | 319 | 4 |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **167** | 163 | 158 |
| Natural gas liquids (MBD) | | **14** | 12 | 13 |
| Natural gas (MMCFD) | | **7** | 25 | 42 |
| **Total Production** (MBOED) | | **182** | 179 | 178 |
| **Average Sales Prices** | | | | |
| Crude oil (per barrel) | $ | **53.33** | 41.93 | 51.61 |
| Natural gas (per thousand cubic feet) | | **2.72** | 5.22 | 4.33 |

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids, natural gas and LNG. In 2017, Alaska contributed 22 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

*2017 vs. 2016*

Alaska reported earnings of $1,466 million in 2017, compared with earnings of $319 million in 2016. The increase in earnings was mainly due to an $892 million tax benefit from the revaluation of allocated U.S. deferred taxes at a lower federal statutory rate, in accordance with the newly enacted Tax Legislation. Earnings were additionally improved due to higher crude oil prices in 2017. The earnings increase was partly offset by a $110 million after-tax impairment charge for the associated properties, plants and equipment of our small interest in the Point Thomson unit.

Average production increased 2 percent in 2017 compared with 2016, as the impact of normal field decline was more than offset by well performance in the Western North Slope, Greater Prudhoe and Greater Kuparuk areas and lower unplanned downtime.

*2016 vs. 2015*

Alaska reported earnings of $319 million in 2016, compared with earnings of $4 million in 2015. The increase in earnings was mainly due to:

- Lower exploration expenses, primarily due to the absence of the 2015 impairment charge for our Chukchi Sea leasehold and capitalized interest. For additional information on our impairments, see Note 8—Impairments, in the Notes to Consolidated Financial Statements.
- Reduced production and operating expense, mainly from lower maintenance costs and general and administrative expenses.
- Enhanced oil recovery tax credits.

- Higher crude oil sales volumes, partly offset by the absence of LNG sales volumes.
- A $57 million after-tax impact for the recognition of state deferred tax assets.
- A $36 million after-tax gain on the sale of our interest in the Alaska Beluga River Unit natural gas field.

The increase in earnings was partly offset by lower crude oil prices and higher DD&A expense, mainly due to capital additions.

Average production increased 1 percent in 2016 compared with 2015, primarily due to new production from the Alpine CD5 drill site and strong well performance in the Greater Prudhoe Area. The production increase was partly offset by normal field decline.

*Acquisition*

In January 2018, we entered into an agreement to acquire certain oil and gas assets in Alaska for $400 million, subject to customary adjustments. The acquisition is subject to regulatory approval. We will have a 100 percent interest in approximately 1.2 million acres of exploration and development lands, including the Willow Discovery.

**Lower 48**

| | | **2017** | 2016 | 2015 |
|---|---|---|---|---|
| **Net Loss Attributable to ConocoPhillips** (millions of dollars) | **$** | **(2,371)** | (2,257) | (1,932) |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **180** | 195 | 206 |
| Natural gas liquids (MBD) | | **69** | 88 | 94 |
| Natural gas (MMCFD) | | **898** | 1,219 | 1,472 |
| **Total Production** (MBOED) | | **399** | 486 | 545 |
| **Average Sales Prices** | | | | |
| Crude oil (per barrel) | **$** | **47.36** | 37.49 | 42.62 |
| Natural gas liquids (per barrel) | | **22.20** | 14.34 | 14.01 |
| Natural gas (per thousand cubic feet) | | **2.73** | 2.20 | 2.43 |

The Lower 48 segment consists of operations located in the U.S. Lower 48 states and exploration activities in the Gulf of Mexico. During 2017, the Lower 48 contributed 30 percent of our worldwide liquids production and 27 percent of our natural gas production.

*2017 vs. 2016*

Lower 48 reported a loss of $2,371 million after-tax in 2017, compared with a loss of $2,257 million after-tax in 2016. The increase in loss was primarily due to proved property impairments in 2017, totaling $2.5 billion after-tax, for our interests in the San Juan Basin and the Barnett which were written down to fair value less costs to sell. Lower natural gas, crude oil and natural gas liquids sales volumes from asset dispositions and normal field decline further increased losses during the year.

The increase in losses was partly offset by:

- Lower DD&A expense, mainly resulting from a lower unit-of-production rate from reserve revisions, disposition impacts and lower volumes.
- A $689 million tax benefit, primarily related to the revaluation of allocated U.S. deferred taxes at a lower federal statutory rate, in accordance with the newly enacted Tax Legislation.
- Higher realized crude oil, natural gas liquids and natural gas prices.
- Lower exploration expenses mainly due to:
  - Lower leasehold impairment expense, primarily the absence of 2016 after-tax charges of $132 million for our Gibson and Tiber leaseholds; $62 million for our Melmar leasehold and $52 million for various Gulf of Mexico leases after completion of marketing efforts. The reduction was partly offset by an after-tax charge of $33 million for Shenandoah in deepwater Gulf of Mexico and an after-tax charge of $24 million for certain mineral assets, both in 2017.
  - Lower other exploration expenses, mainly due to the absence of a $95 million after-tax expense in 2016 related to the cancellation of our final Gulf of Mexico deepwater drillship contract.
  - Lower dry hole costs primarily due to the absence of 2016 after-tax charges in deepwater Gulf of Mexico of $162 million for our Gibson and Tiber wells, and $83 million for our Melmar well, partly offset by 2017 after-tax charges of $187 million for multiple wells in Shenandoah and $41 million for several wells in the Powder River Basin.

In 2017, our average realized crude oil price of $47.36 per barrel was 7 percent less than WTI of $50.90 per barrel. The differential is driven primarily by local market dynamics in the Gulf Coast and Bakken.

Total average production decreased 18 percent in 2017 compared with 2016. The decrease was mainly attributable to normal field decline and the disposition of our interests in the San Juan Basin, partly offset by new production, primarily from Eagle Ford and Bakken.

*Asset Disposition*
On July 31, 2017, we completed the sale of our interests in the San Juan Basin for total proceeds comprised of $2.5 billion in cash after customary adjustments and a contingent payment of up to $300 million. The six-year contingent payment, effective beginning January 1, 2018, is due annually for the periods in which the monthly U.S. Henry Hub price is at or above $3.20 per million British thermal units.

On September 29, 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments.

For additional information on our asset sales in the Lower 48, see Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements.

*2016 vs. 2015*

Lower 48 reported a loss of $2,257 million after-tax in 2016, compared with a loss of $1,932 million after-tax in 2015. The increase in losses was primarily due to:

- The absence of a $368 million after-tax gain on the disposition of certain properties in South Texas, East Texas and North Louisiana.
- Lower crude oil and natural gas prices.
- Lower sales volumes across all commodities due to dispositions and field decline.
- Higher proved property impairments, including a $49 million after-tax impairment associated with changes to development plans for Eagle Ford infrastructure.

The increase in losses was partly offset by:

- Lower production and operating expenses, mainly due to reduced activity and cost efficiencies.
- Lower exploration expenses, mainly due to:

    - Reduced other exploration costs, mainly due to the absence of a $216 million after-tax charge related to the termination of our Gulf of Mexico deepwater drillship contract with Ensco in 2015, partly offset by 2016 rig cancellation and related third party costs of $95 million after-tax for our final Gulf of Mexico deepwater drillship contract.
    - Lower general and administrative, and geological and geophysical expenses.
    - Lower leasehold impairment expense, including the absence of 2015 after-tax charges of $154 million for certain leases in the Gulf of Mexico and $100 million for various blocks in the Gila Prospect. The decrease in leasehold impairment was partly offset by 2016 after-tax charges of $132 million for our Gibson and Tiber leaseholds and $62 million for the Melmar Prospect, all in the Gulf of Mexico.
    - Lower exploration expenses were partly offset by slightly increased dry hole costs in 2016, including after-tax charges in deepwater Gulf of Mexico of $162 million for our Gibson and Tiber wells and $83 million associated with our Melmar well. Dry hole costs in 2016 were partly offset by the absence of a $111 million after-tax charge in 2015 associated with two wells in the Gila Prospect in the deepwater Gulf of Mexico.

- An $88 million gain associated with our receipt of Greater Northern Iron Ore Properties Trust assets in the fourth quarter of 2016.
- A $48 million after-tax benefit from a damage claim settlement.
- A $38 million after-tax gain from the disposition of noncore assets and lease exchanges.
- Lower DD&A, mainly due to 2016 reserve additions and reduced volumes, partly offset by price-related reserve revisions.

Total average production decreased 11 percent in 2016 compared with 2015. The decrease was mainly attributable to normal field decline and the 2015 disposition of noncore properties in East Texas and North Louisiana, as well as South Texas. The reduction was partly offset by new production and well performance, primarily from Eagle Ford, Bakken and the Permian Basin, as well as lower unplanned downtime.

**Canada**

| | | 2017 | 2016 | 2015 |
|---|---|---|---|---|
| **Net Income (Loss) Attributable to ConocoPhillips** | | | | |
| (millions of dollars) | $ | **2,564** | (935) | (1,044) |
| | | | | |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **3** | 7 | 12 |
| Natural gas liquids (MBD) | | **9** | 23 | 26 |
| Bitumen (MBD) | | | | |
| Consolidated operations | | **59** | 35 | 13 |
| Equity affiliates | | **63** | 148 | 138 |
| Total bitumen | | **122** | 183 | 151 |
| | | | | |
| Natural gas (MMCFD) | | **187** | 524 | 715 |
| | | | | |
| **Total Production** (MBOED) | | **165** | 300 | 308 |
| | | | | |
| **Average Sales Prices** | | | | |
| Crude oil (per barrel) | $ | **43.69** | 35.25 | 39.52 |
| Natural gas liquids (per barrel) | | **21.51** | 14.82 | 17.02 |
| Bitumen (dollars per barrel) | | | | |
| Consolidated operations | | **21.43** | 12.91 | 20.13 |
| Equity affiliates | | **23.83** | 15.80 | 18.58 |
| Total bitumen | | **22.66** | 15.27 | 18.72 |
| Natural gas (per thousand cubic feet) | | **1.93** | 1.49 | 1.91 |

Our Canadian operations mainly consist of an oil sands development in the Athabasca region of northeastern Alberta and a liquids-rich unconventional play in western Canada. In 2017, Canada contributed 16 percent of our worldwide liquids production and 6 percent of our worldwide natural gas production.

*2017 vs. 2016*

Canada operations reported earnings of $2,564 million in 2017, an increase of $3,499 million compared with 2016. The earnings increase was mainly due to an after-tax gain of $1.6 billion on the sale of certain Canadian assets, further discussed below, as well as the recognition of $996 million in deferred tax benefits related to the capital gains component of our disposition and the recognition of previously unrealizable Canadian tax basis.

In addition to the items discussed above, earnings were further increased due to:

- Lower DD&A, mainly from disposition impacts.
- Lower dry hole costs, mainly due to the absence of 2016 combined after-tax charges in offshore Nova Scotia of $187 million for our Cheshire and Monterey Jack wells.
- Higher realized prices across all commodities.
- A $114 million tax benefit related to our prior decision to exit Nova Scotia deepwater exploration.
- Lower production and operating expenses.
- Improved equity earnings, as improved prices and reduced DD&A more than offset the volume loss from our Canada disposition.

The earnings increase was partly offset by additional volume reductions from the disposition of our western Canada gas assets.

Total average production decreased 45 percent in 2017 compared with 2016. The production decrease was primarily due to the Canada disposition, partly offset by production ramp-up at Surmont.

*Asset Disposition*
On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction was $11.0 billion in cash after customary adjustments, 208 million Cenovus Energy common shares and a five-year uncapped contingent payment. The contingent payment, calculated and paid on a quarterly basis, is $6 million Canadian dollars (CAD) for every $1 CAD by which the Western Canada Select (WCS) quarterly average crude price exceeds $52 CAD per barrel. See Note 4—Assets Held for Sale, Sold or Acquired and Note 6—Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements, for additional information regarding our Canada disposition.

*2016 vs. 2015*

Canada operations reported a loss of $935 million in 2016, a decrease in loss of $109 million compared with 2015. The decrease in loss was primarily due to:

- The absence of a $136 million impact of a 2 percent increase in Alberta corporate tax rates on deferred taxes in 2015.
- Lower production and operating expenses, mainly due to reduced headcount and the disposition of noncore assets in western Canada.
- Lower exploration expenses, mainly due to:
    - Reduced leasehold impairment expense, including the absence of an impairment charge for undeveloped leasehold in the Duvernay, Thornbury, Saleski and Crow Lake areas. The reduction in leasehold impairment expense was partly offset by a $23 million after-tax charge in the fourth quarter of 2016 primarily due to decisions to discontinue further testing on undeveloped leaseholds.
    - Lower general and administrative, and geological and geophysical expenses.
    - Lower dry hole costs, mainly due to the absence of 2015 charges associated with our Horn River, Northwest Territories, Thornbury and Saleski properties, partly offset by dry hole costs in 2016, including total after-tax charges in offshore Nova Scotia of $187 million for our Cheshire and Monterey Jack wells.
- Higher gains on dispositions, including the absence of a $103 million net after-tax loss on the disposition of noncore assets in western Canada in 2015.

The decrease in loss was partly offset by lower commodity prices; higher DD&A expense, mainly from price-related reserve revisions; and a $42 million after-tax impairment charge related to certain developed properties in central Alberta, which were classified as held for sale, being written down to fair value less costs to sell.

Total average production decreased 3 percent in 2016 compared with 2015, while bitumen production increased 21 percent over the same periods. The decrease in total production was mainly attributable to the disposition of noncore assets in western Canada and normal field decline. The production decrease was partly offset by strong well performance in western Canada, Surmont and FCCL.

**Europe and North Africa**

| | | **2017** | 2016 | 2015 |
|---|---|---|---|---|
| **Net Income Attributable to ConocoPhillips** (millions of dollars) | $ | **553** | 394 | 409 |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **142** | 122 | 120 |
| Natural gas liquids (MBD) | | **8** | 7 | 7 |
| Natural gas (MMCFD) | | **484** | 460 | 476 |
| **Total Production** (MBOED) | | **230** | 205 | 207 |
| **Average Sales Prices** | | | | |
| Crude oil (dollars per barrel) | $ | **54.21** | 43.66 | 52.75 |
| Natural gas liquids (per barrel) | | **34.07** | 22.62 | 27.56 |
| Natural gas (per thousand cubic feet) | | **5.70** | 4.71 | 7.14 |

The Europe and North Africa segment consists of operations principally located in the Norwegian and U.K. sectors of the North Sea, the Norwegian Sea and Libya. In 2017, our Europe and North Africa operations contributed 18 percent of our worldwide liquids production and 15 percent of our natural gas production.

*2017 vs. 2016*

Earnings for Europe and North Africa operations of $553 million increased 40 percent in 2017. The increase in earnings was primarily due to higher realized crude oil, natural gas and natural gas liquids prices. Earnings were additionally improved by lower DD&A, mainly due to reserve revisions; a $60 million tax benefit from the revaluation of allocated U.S. deferred taxes at a lower U.S. federal statutory rate, in accordance with the newly enacted Tax Legislation; and a $41 million tax benefit in Norway.

The increase in earnings was partly offset by the absence of a 2016 net deferred tax benefit of $161 million resulting from a change in the U.K. tax rate and a lower credit to impairment in 2017, compared to 2016, reflecting the annual updates to asset retirement obligations (ARO) on fields at or nearing the end of life which were impaired in prior years. The earnings improvement was further reduced by a net deferred tax charge of $65 million in the U.K. resulting from updated assumptions regarding applicable tax rates.

Average production increased 12 percent in 2017, compared with 2016. The increase was mainly due to the resumption and ramp-up of production in Libya; improved drilling and well performance in Norway; new production from the Greater Britannia Area and Norway; and higher Norway gas offtake, partly offset by normal field decline.

*2016 vs. 2015*

Earnings for Europe and North Africa operations of $394 million decreased 4 percent in 2016. The decrease in earnings was primarily due to the absence of a $555 million net deferred tax benefit as a result of a change in the U.K. tax rate, effective at the beginning of 2015; lower crude oil and natural gas prices; lower sales volumes; and the absence of a 2015 after-tax gain of $49 million on the sale of our 1.9 percent interest in Norwegian Continental Shelf Gas Transportation (Gassled).

The decrease in earnings was partly offset by:

- Lower property impairments, including the absence of 2015 after-tax charges of $317 million in the U.K. due to lower crude oil and natural gas prices, and a $180 million credit to impairment in 2016 due to decreased ARO estimates on fields at or nearing the end of life which were impaired in prior years. The reduction in property impairments was partly offset by a $59 million after-tax charge associated with our Calder Field and Rivers terminal in the U.K. For additional information on our impairments, see Note 8—Impairments, in the Notes to Consolidated Financial Statements.
- Lower DD&A expense in the U.K. driven by reduced rate, as a result of completed depreciation on the Brodgar H3 tie-back well in 2015, and lower volumes.
- A $161 million net deferred tax benefit resulting from a reduction in the U.K. tax rate, which was enacted in September 2016 and effective January 1, 2016.
- Reduced operating expenses across the segment.

Average production decreased 1 percent in 2016, compared with 2015. The decrease in production was mainly due to normal field decline, partly offset by improved drilling and well performance in Norway and new production from the Greater Ekofisk and Greater Britannia areas. Libya production remained largely shut in, as the Es Sider crude oil export terminal closure continued throughout the third quarter of 2016. Production resumed in Libya in October 2016.

**Asia Pacific and Middle East**

| | | 2017 | 2016 | 2015 |
|---|---|---|---|---|
| **Net Income (Loss) Attributable to ConocoPhillips** | | | | |
| (millions of dollars) | $ | **(1,098)** | 209 | (463) |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | | | |
| Consolidated operations | | **93** | 97 | 91 |
| Equity affiliates | | **14** | 14 | 14 |
| Total crude oil | | **107** | 111 | 105 |
| Natural gas liquids (MBD) | | | | |
| Consolidated operations | | **4** | 7 | 9 |
| Equity affiliates | | **7** | 8 | 7 |
| Total natural gas liquids | | **11** | 15 | 16 |
| Natural gas (MMCFD) | | | | |
| Consolidated operations | | **687** | 730 | 717 |
| Equity affiliates | | **1,007** | 899 | 638 |
| Total natural gas | | **1,694** | 1,629 | 1,355 |
| **Total Production** (MBOED) | | **401** | 399 | 347 |
| **Average Sales Prices** | | | | |
| Crude oil (dollars per barrel) | | | | |
| Consolidated operations | $ | **54.38** | 42.23 | 49.70 |
| Equity affiliates | | **54.76** | 44.11 | 53.12 |
| Total crude oil | | **54.43** | 42.47 | 50.16 |
| Natural gas liquids (dollars per barrel) | | | | |
| Consolidated operations | | **41.37** | 29.00 | 37.78 |
| Equity affiliates | | **38.74** | 31.13 | 35.79 |
| Total natural gas liquids | | **39.75** | 30.11 | 36.88 |
| Natural gas (dollars per thousand cubic feet) | | | | |
| Consolidated operations | | **4.98** | 4.31 | 6.23 |
| Equity affiliates | | **4.27** | 2.97 | 4.83 |
| Total natural gas | | **4.55** | 3.57 | 5.58 |

The Asia Pacific and Middle East segment has operations in China, Indonesia, Malaysia, Australia, Timor-Leste and Qatar, as well as exploration activities in Brunei. During 2017, Asia Pacific and Middle East contributed 14 percent of our worldwide liquids production and 52 percent of our natural gas production.

*2017 vs. 2016*

Asia Pacific and Middle East reported a loss of $1,098 million in 2017, compared with earnings of $209 million in 2016. The increase in loss was mainly due to a $2,384 million before- and after-tax charge for the impairment of our APLNG investment in 2017. For additional information on our APLNG impairment, see the “APLNG” section of Note 5—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements. Additionally, lower sales volumes in Indonesia, Australia and China further increased losses.

The increase in losses was partly offset by higher equity earnings, mainly as a result of higher commodity prices, increased sales volumes at APLNG and the absence of a 2016 deferred tax charge of $174 million resulting from the change of our APLNG tax functional currency. Higher realized crude oil and natural gas prices on non-equity volumes further reduced the loss.

Average production was essentially flat in 2017.

*2016 vs. 2015*

Asia Pacific and Middle East reported earnings of $209 million in 2016, compared with a loss of $463 million in 2015. The earnings increase was mainly due to:

- The absence of a $1,502 million before- and after-tax charge for the impairment of our APLNG investment in 2015. For additional information on our APLNG impairment, see the "APLNG" section of Note 5—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.
- Higher LNG sales volumes.
- Lower production taxes.
- Reduced feedstock costs at Darwin LNG.
- Lower operating expenses, mainly due to lower general and administrative spend, maintenance costs and transportation expenses across the segment.
- Lower exploration expenses, mainly due to lower dry hole costs, as well as the absence of a $41 million after-tax charge in 2015 for the impairment of our relinquished Palangkaraya PSC, and reduced exploration general and administrative expense.

The earnings increase was partly offset by lower prices across all commodities; lower equity earnings from APLNG, mainly as a result of higher DD&A expense from APLNG Trains 1 and 2 coming online; and a third-quarter 2016 deferred tax charge of $174 million resulting from APLNG's tax functional currency change.

Average production increased 15 percent in 2016, compared with 2015. The production increase in 2016 was mainly attributable to new production from the ramp-up of APLNG in Australia and the Kebabangan gas field in Malaysia, improved drilling and well performance in China and Malaysia, and increased recoveries from production sharing contracts in Indonesia. The production increase was partially offset by normal field decline across the segment.

**Other International**

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| **Net Income (Loss) Attributable to ConocoPhillips** (millions of dollars) | $ **167** | (16) | (593) |
| **Average Net Production** | | | |
| Crude oil (MBD) | | | |
| Equity affiliates | - | - | 4 |
| **Total Production** (MBOED) | - | - | 4 |
| **Average Sales Prices** | | | |
| Crude oil (dollars per barrel) | | | |
| Equity affiliates | - | - | 37.21 |

The Other International segment includes exploration activities in Colombia and Chile.

*2017 vs. 2016*

Other International operations reported earnings of $167 million in 2017, compared with a loss of $16 million in 2016. The increase in earnings was primarily due to a $320 million before- and after-tax ICSID award from an arbitration with The Republic of Ecuador. Earnings were additionally increased due to lower rig stacking costs in Angola. The increase in earnings was partly offset by the absence of a $138 million gain in 2016 on the disposition of ConocoPhillips Senegal B.V., the entity that held our interest in three exploration blocks offshore Senegal, and a $45 million tax charge from the revaluation of allocated U.S. deferred taxes at a lower U.S. federal statutory rate, in accordance with the newly enacted Tax Legislation.

*2016 vs. 2015*

Other International operations reported a loss of $16 million in 2016, compared with a loss of $593 million in 2015. The decrease in losses was primarily due to the absence of after-tax charges in 2015 of $235 million, $75 million and $32 million net for property impairments on our Angola Block 36, Angola Block 37 and Poland leasehold, respectively. Additionally, losses decreased due to the absence of the 2015 after-tax dry hole expenses offshore Angola of $81 million for the Omosi-1 well and $59 million for the Vali-1 well, combined with a $138 million gain on the 2016 disposition of ConocoPhillips Senegal B.V., the entity that held our interest in three exploration blocks offshore Senegal.

**Corporate and Other**

| | Millions of Dollars | | |
|---|---|---|---|
| | **2017** | 2016 | 2015 |
| **Net Loss Attributable to ConocoPhillips** | | | |
| Net interest | $ **(739)** | (980) | (518) |
| Corporate general and administrative expenses | **(284)** | (289) | (246) |
| Technology | **20** | 50 | 122 |
| Other | **(1,133)** | (110) | (167) |
| | $ **(2,136)** | (1,329) | (809) |

*2017 vs. 2016*

Net interest consists of interest and financing expense, net of interest income and capitalized interest. Net interest decreased 25 percent in 2017 compared with 2016, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and lower interest as a result of reduced debt. Higher interest income further drove the decrease in net interest, which was partly offset by lower capitalized interest on projects.

Corporate general and administrative expenses which include pension settlement expenses and compensation program costs was essentially flat in 2017.

Technology includes our investment in new technologies or businesses, as well as licensing revenues received. Activities are focused on tight oil reservoirs, LNG, oil sands and other production operations. Earnings from Technology were $20 million in 2017, compared with $50 million in 2016. The decrease in earnings primarily resulted from lower licensing revenues, partly offset by reduced technology program spend.

The category “Other” includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, other costs not directly associated with an operating segment and premiums incurred on the early retirement of debt. “Other” expenses increased $1,023 million in 2017, mainly due to an $813 million tax charge from the revaluation of deferred taxes at a lower federal statutory rate, in accordance with the newly enacted Tax Legislation and premiums on our early retirement of debt.

*2016 vs. 2015*

Net interest increased 89 percent in 2016 compared with 2015, primarily as a result of the absence of the 2015 impacts from the fair market value of apportioning interest expense in the United States, lower capitalized interest on projects, and increased debt.

Corporate general and administrative expenses increased 17 percent in 2016, mainly due to increases from market impacts on certain compensation programs, partly offset by lower staff expenses.

Earnings from Technology were $50 million in 2016, compared with $122 million in 2015. The decrease in earnings primarily resulted from lower licensing revenues, partly offset by reduced technology program spend.

“Other” expenses decreased 34 percent in 2016, mainly due to lower restructuring costs and favorable foreign currency impacts, partly offset by the absence of a 2015 tax benefit.

## CAPITAL RESOURCES AND LIQUIDITY

### Financial Indicators

| | | Millions of Dollars Except as Indicated | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| Net cash provided by operating activities | $ | **7,077** | 4,403 | 7,572 |
| Cash and cash equivalents | | **6,325** | 3,610 | 2,368 |
| Short-term debt | | **2,575** | 1,089 | 1,427 |
| Total debt | | **19,703** | 27,275 | 24,880 |
| Total equity | | **30,801** | 35,226 | 40,082 |
| Percent of total debt to capital* | | **39 %** | 44 | 38 |
| Percent of floating-rate debt to total debt | | **5 %** | 9 | 7 |

**Capital includes total debt and total equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources, including cash generated from operating activities, proceeds from asset sales, our commercial paper and credit facility programs and our shelf registration statement. In 2017, the primary uses of our available cash were $7,876 million to reduce debt; $4,591 million to support our ongoing capital expenditures and investments program; $1,305 million to pay dividends on our common stock; $1,790 million net purchases of short-term investments; $3,000 million to repurchase our common stock; and a $600 million contribution to our domestic qualified pension plan. During 2017, cash and cash equivalents increased by $2,715 million to $6,325 million.

We believe current cash balances and cash generated by operations, together with access to external sources of funds as described below in the "Significant Sources of Capital" section, will be sufficient to meet our funding requirements in the near and long term, including our capital spending program, share repurchases, dividend payments and required debt payments.

### Significant Sources of Capital

*Operating Activities*
During 2017, cash provided by operating activities was $7,077 million, a 61 percent increase from 2016. The increase was primarily due to higher prices across all commodities.

While the stability of our cash flows from operating activities benefits from geographic diversity, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, bitumen, natural gas, LNG and natural gas liquids. Prices and margins in our industry have historically been volatile and are driven by market conditions over which we have no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

The level of absolute production volumes, as well as product and location mix, impacts our cash flows. Our 2017 production averaged 1,377 MBOED. Full-year 2018 production is expected to be 1,195 to 1,235 MBOED. This results in approximately 5 percent growth compared with full-year 2017 underlying production, which excludes the impact of closed and planned dispositions of 191 MBOED. Production guidance for 2018 excludes Libya. Future production is subject to numerous uncertainties, including, among others, the volatile crude oil and natural gas price environment, which may impact investment decisions; the effects of price changes on production sharing and variable-royalty contracts; acquisition and disposition of fields; field production decline rates; new technologies; operating efficiencies; timing of startups and major turnarounds; political instability; weather-related disruptions; and the addition of proved reserves through exploratory success and their timely and cost-effective development. While we actively manage these factors, production levels can cause variability in cash flows, although generally this variability has not been as significant as that caused by commodity prices.

To maintain or grow our production volumes on an ongoing basis, we must continue to add to our proved reserve base. Our total reserve replacement in 2017 was negative 168 percent. Our organic reserve replacement, which excludes the impact of sales and purchases, was 200 percent in 2017. Over the five-year period ended December 31, 2017, our reserve replacement was a negative 24 percent (including 3 percent from consolidated operations) reflecting the impact of asset dispositions and lower prices. The total reserve replacement amount above is based on the sum of our net additions (revisions, improved recovery, purchases, extensions and discoveries, and sales) divided by our production, as shown in our reserve table disclosures. For additional information about our 2018 capital budget, see the "2018 Capital Budget" section within "Capital Resources and Liquidity" and for additional information on proved reserves, including both developed and undeveloped reserves, see the "Oil and Gas Operations" section of this report.

As discussed in the "Critical Accounting Estimates" section, engineering estimates of proved reserves are imprecise; therefore, each year reserves may be revised upward or downward due to the impact of changes in commodity prices or as more technical data becomes available on reservoirs. In 2017, revisions increased reserves, while in 2016 and 2015, revisions decreased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future.

*Investing Activities*
Proceeds from asset sales in 2017 were $13.9 billion. We completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction included $11.0 billion in cash after customary adjustments and 208 million Cenovus Energy common shares. We completed the sale of our interests in the San Juan Basin to an affiliate of Hilcorp Energy Company. Total proceeds for the sale was $2.5 billion in cash after customary adjustments. We also completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments.

Proceeds from asset dispositions in 2016 were $1.3 billion, primarily from the sales of ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal; our 40 percent interest in South Natuna Sea Block B in Indonesia; our interest in the Alaska Beluga River Unit natural gas field in the Cook Inlet; and certain mineral and non-mineral fee lands in northeastern Minnesota.

For additional information on our dispositions and investment in Cenovus common shares, see Note 4—Assets Held for Sale, Sold or Acquired and Note 6—Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements, and the Results of Operations section within Management's Discussion and Analysis.

*Commercial Paper and Credit Facilities*
We have a revolving credit facility totaling $6.75 billion, expiring in June 2019. Our revolving credit facility may be used for direct bank borrowings, the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper programs. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the United States. The agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

We have two commercial paper programs. The ConocoPhillips $6.25 billion commercial paper program is available to fund short-term working capital needs. We also have the ConocoPhillips Qatar Funding Ltd. $500 million commercial paper program, which is used to fund commitments relating to QG3. Commercial paper maturities are generally limited to 90 days. We had no commercial paper outstanding at December 31, 2017 or 2016, under either the ConocoPhillips or the ConocoPhillips Qatar Funding Ltd. commercial paper program. We had no direct borrowings or letters of credit issued under the revolving credit facility. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.75 billion in borrowing capacity under our revolving credit facility at December 31, 2017.

In the first quarter of 2017, Fitch and Standard & Poor's reflected an improvement in their outlook for our debt from "negative" to "stable" and affirmed our long-term debt rating at "A-." In January 2018, Fitch further improved their outlook for our debt from "stable" to "positive." After improving their outlook for our debt from "negative" to "positive" in the first quarter of 2017, Moody's Investor Services upgraded our long-term debt rating from "Baa2" to "Baa1" with a stable outlook in the third quarter of 2017 in response to our debt reduction. We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity, in the event of a downgrade of our credit rating. If our credit rating were downgraded, it could increase the cost of corporate debt available to us and restrict our access to the commercial paper markets. If our credit rating were to deteriorate to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our revolving credit facility.

Certain of our project-related contracts, commercial contracts and derivative instruments contain provisions requiring us to post collateral. Many of these contracts and instruments permit us to post either cash or letters of credit as collateral. At December 31, 2017 and 2016, we had direct bank letters of credit of $338 million and $304 million, respectively, which secured performance obligations related to various purchase commitments incident to the ordinary conduct of business. In the event of credit ratings downgrades, we may be required to post additional letters of credit.

*Shelf Registration*
We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission (SEC) under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

**Off-Balance Sheet Arrangements**

As part of our normal ongoing business operations and consistent with normal industry practice, we enter into numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements.

For information about guarantees, see Note 11—Guarantees, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

## Capital Requirements

For information about our capital expenditures and investments, see the "Capital Expenditures" section.

Our debt balance at December 31, 2017, was $19.7 billion, a decrease of $7.6 billion from the balance at December 31, 2016.

In 2017, two notes totaling $1,001 million were paid at maturity, including the $1.0 billion 1.05% Notes due 2017. Also in 2017, we prepaid the $1,450 million term loan facility due in 2019. We also redeemed a total $5.0 billion of debt, described below, incurring $301 million in premiums above book value, which are reported in the "Other expense" line on our consolidated income statement.

- 6.65% Debentures due 2018 with principal of $297 million.
- 5.20% Notes due 2018 with principal of $500 million.
- 1.5% Notes due 2018 with principal of $750 million.
- 5.75% Notes due 2019 with principal of $2.25 billion.
- 6.00% Notes due 2020 with principal of $1.0 billion.
- 4.20% Notes due 2021 with principal of $1.25 billion (partial redemption of $250 million).

In the fourth quarter of 2017, we gave notice to redeem the following debt instruments totaling $2.25 billion.

- 2.2% Notes due 2020 with principal of $500 million.
- 4.20% Notes due 2021 with remaining principal of $1.0 billion.
- 2.875% Notes due 2021 with principal of $750 million.

The prepayments occurred on January 22, 2018, and we incurred premiums above book value of $75 million.

On a longer-term basis our debt target is $15 billion by year-end 2019. In the future, we may redeem other debt instruments or purchase debt instruments in the open market or otherwise, as we seek to achieve this target. Any such redemptions or purchases would be subject to market conditions and other factors, and may be conducted or discontinued at any time without prior notice. For more information on Debt, see Note 10—Debt, in the Notes to Consolidated Financial Statements.

On January 31, 2017, we announced a 6 percent increase in the quarterly dividend to $0.265 per share. The dividend was paid on March 1, 2017, to stockholders of record at the close of business on February 14, 2017. On May 5, 2017, we announced a quarterly dividend of $0.265 per share. The dividend was paid on June 1, 2017, to stockholders of record at the close of business on May 15, 2017. On July 12, 2017, we announced a quarterly dividend of $0.265 per share. The dividend was paid on September 1, 2017, to stockholders of record at the close of business on July 24, 2017. On October 6, 2017, we announced a quarterly dividend of $0.265 per share which was paid on December 1, 2017, to stockholders of record at the close of business on October 16, 2017. Additionally, on February 1, 2018, we announced an increase in the quarterly dividend to $0.285 per share, compared with the previous quarterly dividend of $0.265 per share. The dividend is payable on March 1, 2018, to stockholders of record at the close of business on February 12, 2018.

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock through 2019. On March 29, 2017, we announced plans to double our share repurchase program to $6 billion of common stock through 2019, with $3 billion allocated and purchased in 2017, and the remainder allocated evenly to 2018 and 2019. On February 1, 2018, we announced the acceleration of our previously stated 2018 share repurchases from $1.5 billion to $2.0 billion, with the remaining balance to be repurchased in 2019. Since our share repurchase program began in November 2016, we have repurchased 66 million shares at a cost of $3.1 billion through December 31, 2017.

In addition to our previously announced share repurchase program above, we are currently planning to purchase up to an additional $1.5 billion of our common stock through 2020. Whether we undertake these additional repurchases is ultimately subject to numerous considerations, including Board authorization, market conditions and other factors. See Risk Factors "Our ability to declare and pay dividends and repurchase shares is subject to certain considerations."

During the third quarter of 2017, we made a $600 million contribution to our domestic qualified pension plan, which is included in the "Other" line in the "Cash Flows From Operating Activities" section of our consolidated statement of cash flows. This additional contribution significantly lowers our domestic pension deficit which will reduce future premiums charged by the Pension Benefit Guaranty Corporation. It also mitigates the need for contributions in future quarters.

**Contractual Obligations**

The table below summarizes our aggregate contractual fixed and variable obligations as of December 31, 2017:

| | Millions of Dollars | | | | |
|---|---|---|---|---|---|
| | Payments Due by Period | | | | |
| | Total | Up to 1 Year | Years 2–3 | Years 4–5 | After 5 Years |
| Debt obligations (a) | $ 18,929 | 2,508 | 63 | 1,706 | 14,652 |
| Capital lease obligations (b) | 774 | 67 | 147 | 132 | 428 |
| Total debt | 19,703 | 2,575 | 210 | 1,838 | 15,080 |
| Interest on debt and other obligations | 13,884 | 955 | 1,881 | 1,834 | 9,214 |
| Operating lease obligations (c) | 1,548 | 278 | 628 | 433 | 209 |
| Purchase obligations (d) | 10,102 | 4,210 | 1,833 | 945 | 3,114 |
| Other long-term liabilities | | | | | |
| Pension and postretirement benefit contributions (e) | 1,312 | 210 | 491 | 611 | - |
| Asset retirement obligations (f) | 7,798 | 251 | 687 | 575 | 6,285 |
| Accrued environmental costs (g) | 180 | 25 | 36 | 29 | 90 |
| Unrecognized tax benefits (h) | 51 | 51 | (h) | (h) | (h) |
| Total | $ 54,578 | 8,555 | 5,766 | 6,265 | 33,992 |

(a) Includes $252 million of net unamortized premiums, discounts and debt issuance costs. See Note 10—Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) Capital lease obligations are presented on a discounted basis.

(c) Operating lease obligations are presented on an undiscounted basis.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms, presented on an undiscounted basis. Does not include purchase commitments for jointly owned fields and facilities where we are not the operator.

The majority of the purchase obligations are market-based contracts related to our commodity business. Product purchase commitments with third parties totaled $3,487 million.

Purchase obligations of $5,443 million are related to agreements to access and utilize the capacity of third-party equipment and facilities, including pipelines and LNG and product terminals, to transport, process, treat and store commodities. The remainder is primarily our net share of purchase commitments for materials and services for jointly owned fields and facilities where we are the operator.

(e) Represents contributions to qualified and nonqualified pension and postretirement benefit plans for the years 2018 through 2022. For additional information related to expected benefit payments subsequent to 2022, see Note 17—Employee Benefit Plans, in the Notes to Consolidated Financial Statements.

(f) Represents estimated discounted costs to retire and remove long-lived assets at the end of their operations.

(g) Represents estimated costs for accrued environmental expenditures presented on a discounted basis for costs acquired in various business combinations and an undiscounted basis for all other accrued environmental costs.

(h) Excludes unrecognized tax benefits of $831 million because the ultimate disposition and timing of any payments to be made with regard to such amounts are not reasonably estimable. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

**Capital Expenditures**

| | Millions of Dollars | | |
|---|---|---|---|
| | **2017** | 2016 | 2015 |
| Alaska | $ **815** | 883 | 1,352 |
| Lower 48 | **2,136** | 1,262 | 3,765 |
| Canada | **202** | 698 | 1,255 |
| Europe and North Africa | **872** | 1,020 | 1,573 |
| Asia Pacific and Middle East | **482** | 838 | 1,812 |
| Other International | **21** | 104 | 173 |
| Corporate and Other | **63** | 64 | 120 |
| Capital Program | $ **4,591** | 4,869 | 10,050 |

Our capital expenditures and investments for the three-year period ended December 31, 2017, totaled $19.5 billion. The 2017 expenditures supported key exploration and developments, primarily:

- Oil and natural gas development and exploration and appraisal activities in the Lower 48, including Eagle Ford, Bakken, the Permian Basin, the Niobrara in the Denver-Julesburg Basin and several emerging plays.
- Alaska activities related to development in the Western North Slope, Greater Kuparuk Area, and the Greater Prudhoe Area.
- Development activities in Europe, including the Greater Ekofisk Area, Clair Ridge, Aasta Hansteen, and Heidrun.
- Continued oil sands development and appraisal activities in liquids-rich plays in Canada.
- Continued development in Malaysia, Indonesia, China, and Australia; appraisal activity in Australia and exploration activity in Malaysia.

2018 CAPITAL BUDGET

In November 2017, we announced a 2018 capital budget of $5.5 billion, including $3.5 billion of sustaining capital and $2 billion in accretive, short-cycle unconventional programs, future major projects and exploration activities.

We are planning to allocate approximately:

- 51 percent of our 2018 capital expenditures budget to development drilling programs. These funds will focus predominantly on the Lower 48 unconventionals including the Eagle Ford, Bakken and Permian, as well as development drilling in Australia/Timor-Leste, Norway and Alaska.
- 18 percent of our 2018 capital expenditures budget to maintain base production and corporate expenditures.
- 17 percent of our 2018 capital expenditures budget to major projects. These funds will focus on major projects in China, Alaska, Europe and Malaysia.
- 8 percent of our 2018 capital expenditures budget to new exploration activity, primarily in Alaska and the Lower 48.
- 6 percent of our 2018 capital expenditures budget to development appraisal, including the Lower 48, Canada and Alaska.

For information on proved undeveloped reserves and the associated costs to develop these reserves, see the "Oil and Gas Operations" section.

**Contingencies**

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. With respect to income tax related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. For information on other contingencies, see "Critical Accounting Estimates" and Note 12—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

*Legal and Tax Matters*

We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, personal injury, and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required. See Note 18—Income Taxes, in the Notes to Consolidated Financial Statements, for additional information about income tax-related contingencies.

*Environmental*

We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in our industry. The most significant of these environmental laws and regulations include, among others, the:

- U.S. Federal Clean Air Act, which governs air emissions.
- U.S. Federal Clean Water Act, which governs discharges to water bodies.
- European Union Regulation for Registration, Evaluation, Authorization and Restriction of Chemicals (REACH).
- U.S. Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or Superfund), which imposes liability on generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur.
- U.S. Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage and disposal of solid waste.
- U.S. Federal Oil Pollution Act of 1990 (OPA90), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States.
- U.S. Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and response departments.
- U.S. Federal Safe Drinking Water Act, which governs the disposal of wastewater in underground injection wells.
- U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages.
- European Union Trading Directive resulting in European Emissions Trading Scheme.

These laws and their implementing regulations set limits on emissions and, in the case of discharges to water, establish water quality limits. They also, in most cases, require permits in association with new or modified operations. These permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time consuming. In addition, there can be delays associated with notice and comment periods and the agency's processing of the application. Many of the delays associated with the permitting process are beyond the control of the applicant.

Many states and foreign countries where we operate also have, or are developing, similar environmental laws and regulations governing these same types of activities. While similar, in some cases these regulations may impose additional, or more stringent, requirements that can add to the cost and difficulty of marketing or transporting products across state and international borders.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor easily determinable as new standards, such as air emission standards, water quality standards and stricter fuel regulations, continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change, are expected to continue to have an increasing impact on our operations in the United States and in other countries in which we operate. Notable areas of potential impacts include air emission compliance and remediation obligations in the United States and Canada.

An example is the use of hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas otherwise trapped in lower permeability rock formations. A range of local, state, federal or national laws and regulations currently govern hydraulic fracturing operations, with hydraulic fracturing currently prohibited in some jurisdictions. Although hydraulic fracturing has been conducted for many decades, a number of new laws, regulations and permitting requirements are under consideration by the U.S. Environmental Protection Agency (EPA), the U.S. Department of the Interior, and others which could result in increased costs, operating restrictions, operational delays and/or limit the ability to develop oil and natural gas resources. Governmental restrictions on hydraulic fracturing could impact the overall profitability or viability of certain of our oil and natural gas investments. We have adopted operating principles that incorporate established industry standards designed to meet or exceed government requirements. Our practices continually evolve as technology improves and regulations change.

We also are subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations. Such laws and regulations include CERCLA and RCRA and their state equivalents. Longer-term expenditures are subject to considerable uncertainty and may fluctuate significantly.

We occasionally receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2017, there were 14 sites around the United States in which we were identified as a potentially responsible party under CERCLA and comparable state laws.

For most Superfund sites, our potential liability will be significantly less than the total site remediation costs because the percentage of waste attributable to us, versus that attributable to all other potentially responsible parties, is relatively low. Although liability of those potentially responsible is generally joint and several for federal sites and frequently so for state sites, other potentially responsible parties at sites where we are a party typically have had the financial strength to meet their obligations, and where they have not, or where potentially responsible parties could not be located, our share of liability has not increased materially. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or attain a settlement of liability. Actual cleanup costs generally occur after the parties obtain EPA or equivalent state agency approval. There are relatively few sites where we are a major participant, and given the timing and amounts of anticipated expenditures, neither the cost of remediation at those sites nor such costs at all CERCLA sites, in the aggregate, is expected to have a material adverse effect on our competitive or financial condition.

Expensed environmental costs were $398 million in 2017 and are expected to be about $451 million per year in 2018 and 2019. Capitalized environmental costs were $170 million in 2017 and are expected to be about $223 million per year in 2018 and 2019.

Accrued liabilities for remediation activities are not reduced for potential recoveries from insurers or other third parties and are not discounted (except those assumed in a purchase business combination, which we do record on a discounted basis).

Many of these liabilities result from CERCLA, RCRA and similar state or international laws that require us to undertake certain investigative and remedial activities at sites where we conduct, or once conducted, operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites we identified that may require environmental remediation, but which are not currently the subject of CERCLA, RCRA or other agency enforcement activities. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the future, we may incur significant costs under both CERCLA and RCRA.

Remediation activities vary substantially in duration and cost from site to site, depending on the mix of unique site characteristics, evolving remediation technologies, diverse regulatory agencies and enforcement policies, and the presence or absence of potentially liable third parties. Therefore, it is difficult to develop reasonable estimates of future site remediation costs.

At December 31, 2017, our balance sheet included total accrued environmental costs of $180 million, compared with $247 million at December 31, 2016, for remediation activities in the U.S. and Canada. We expect to incur a substantial amount of these expenditures within the next 30 years.

Notwithstanding any of the foregoing, and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent concerns in our operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, we currently do not expect any material adverse effect upon our results of operations or financial position as a result of compliance with current environmental laws and regulations.

*Climate Change*

There has been a broad range of proposed or promulgated state, national and international laws focusing on greenhouse gas (GHG) reduction. These proposed or promulgated laws apply or could apply in countries where we have interests or may have interests in the future. Laws in this field continue to evolve, and while it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation, such laws, if enacted, could have a material impact on our results of operations and financial condition. Examples of legislation or precursors for possible regulation that do or could affect our operations include:

- European Emissions Trading Scheme (ETS), the program through which many of the European Union (EU) member states are implementing the Kyoto Protocol. Our cost of compliance with the EU ETS in 2017 was approximately $1.5 million (net share before-tax).
- The Alberta Specified Gas Emitter regulations require any existing facility with emissions equal to or greater than 100,000 metric tonnes of carbon dioxide or equivalent per year to reduce its net emissions intensity from its baseline. The reduction requirement increased from 15 percent in 2016 to 20 percent in 2017. The total cost of compliance with these regulations in 2017 was approximately $3 million.
- The U.S. Supreme Court decision in Massachusetts v. EPA, 549 U.S. 497, 127 S.Ct. 1438 (2007), confirming that the EPA has the authority to regulate carbon dioxide as an "air pollutant" under the Federal Clean Air Act.
- The U.S. EPA's announcement on March 29, 2010 (published as "Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs," 75 Fed. Reg. 17004 (April 2, 2010)), and the EPA's and U.S. Department of Transportation's joint promulgation of a Final Rule on April 1, 2010, that triggers regulation of GHGs under the Clean Air Act, may trigger more climate-based claims for damages, and may result in longer agency review time for development projects.
- The U.S. EPA's announcement on January 14, 2015, outlining a series of steps it plans to take to address methane and smog-forming volatile organic compound emissions from the oil and gas industry. The former U.S. administration established a goal of reducing the 2012 levels in methane emissions from the oil and gas industry by 40 to 45 percent by 2025.
- Carbon taxes in certain jurisdictions. Our cost of compliance with Norwegian carbon tax legislation in 2017 was approximately $29 million (net share before-tax). We also incur a carbon tax for emissions from fossil fuel combustion in our British Columbia and Alberta Operations totaling just over $1 million (net share before-tax).
- The agreement reached in Paris in December 2015 at the 21st Conference of the Parties to the United Nations Framework on Climate Change, setting out a new process for achieving global emission reductions.

In the United States, some additional form of regulation may be forthcoming in the future at the federal and state levels with respect to GHG emissions. Such regulation could take any of several forms that may result in the creation of additional costs in the form of taxes, the restriction of output, investments of capital to maintain compliance with laws and regulations, or required acquisition or trading of emission allowances. We are working to continuously improve operational and energy efficiency through resource and energy conservation throughout our operations.

Compliance with changes in laws and regulations that create a GHG tax, emission trading scheme or GHG reduction policies could significantly increase our costs, reduce demand for fossil energy derived products, impact the cost and availability of capital and increase our exposure to litigation. Such laws and regulations could also increase demand for less carbon intensive energy sources, including natural gas. The ultimate impact on our financial performance, either positive or negative, will depend on a number of factors, including but not limited to:

- Whether and to what extent legislation or regulation is enacted.
- The timing of the introduction of such legislation or regulation.
- The nature of the legislation (such as a cap and trade system or a tax on emissions) or regulation.
- The price placed on GHG emissions (either by the market or through a tax).
- The GHG reductions required.
- The price and availability of offsets.
- The amount and allocation of allowances.
- Technological and scientific developments leading to new products or services.
- Any potential significant physical effects of climate change (such as increased severe weather events, changes in sea levels and changes in temperature).
- Whether, and the extent to which, increased compliance costs are ultimately reflected in the prices of our products and services.

The company has responded by putting in place a corporate Climate Change Action Plan, together with individual business unit climate change management plans in order to undertake actions in four major areas:

- Equipping the company for a low emission world, for example by integrating GHG forecasting and reporting into company procedures; utilizing GHG pricing in planning economics; and developing systems to handle GHG market transactions.
- Reducing GHG emissions—In 2016, the company reduced or avoided GHG emissions by approximately 114,000 metric tonnes by carrying out a range of programs across our business units. In 2017, we set a long-term target to reduce our greenhouse gas emissions intensity between 5 percent and 15 percent by 2030 from a 2017 baseline. Setting such a target demonstrates our continuing systematic approach to managing climate-related risks throughout the business.
- Evaluating business opportunities such as the creation of offsets and allowances, the use of low carbon energy and the development of low carbon technologies.
- Engaging externally—The company is a sponsor of MIT's Joint Program on the Science and Policy of Global Change; constructively engages in the development of climate change legislation and regulation; and discloses our progress and performance through the Carbon Disclosure Project and the Dow Jones Sustainability Index.

The company uses an estimated market cost of GHG emissions of $40 per metric tonne to evaluate future projects and opportunities.

In 2017 and early 2018, cities and/or counties in California and New York have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. ConocoPhillips will be vigorously defending against these lawsuits.

**Other**

We have deferred tax assets related to certain accrued liabilities, loss carryforwards and credit carryforwards. Valuation allowances have been established to reduce these deferred tax assets to an amount that will, more likely than not, be realized. Based on our historical taxable income, our expectations for the future, and available tax-planning strategies, management expects the net deferred tax assets will be realized as offsets to reversing deferred tax liabilities.

## NEW ACCOUNTING STANDARDS

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-02, "Leases" (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB Accounting Standards Codification (ASC) Topic 840, "Leases," and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements. In January 2018, ASU No. 2016-02 was amended by the provisions of ASU No. 2018-01, "Land Easement Practical Expedient for Transition to Topic 842." We plan to adopt ASU No. 2016-02, as amended, effective January 1, 2019, and continue to evaluate the ASU to determine the impact of adoption on our consolidated financial statements and disclosures, accounting policies and systems, business processes, and internal controls. We also continue to monitor proposals issued by the FASB to clarify the ASU and certain industry implementation issues. While our evaluation of ASU No. 2016-02 and related implementation activities are ongoing, we expect the adoption of the ASU to have a material impact on our consolidated financial statements and disclosures. For additional information, see Note 24—New Accounting Standards, in the Notes to Consolidated Financial Statements.

## CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. See Note 1—Accounting Policies, in the Notes to Consolidated Financial Statements, for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent there is a reasonable likelihood materially different amounts would have been reported under different conditions, or if different assumptions had been used. These critical accounting estimates are discussed with the Audit and Finance Committee of the Board of Directors at least annually. We believe the following discussions of critical accounting estimates, along with the discussions of contingencies and of deferred tax asset valuation allowances in this report, address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

### Oil and Gas Accounting

Accounting for oil and gas exploratory activity is subject to special accounting rules unique to the oil and gas industry. The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs. However, leasehold acquisition costs and exploratory well costs are capitalized on the balance sheet pending determination of whether proved oil and gas reserves have been discovered on the prospect.

*Property Acquisition Costs*
For individually significant leaseholds, management periodically assesses for impairment based on exploration and drilling efforts to date. For relatively small individual leasehold acquisition costs, management exercises judgment and determines a percentage probability that the prospect ultimately will fail to find proved oil and gas reserves and pools that leasehold information with others in the geographic area. For prospects in areas with limited, or no, previous exploratory drilling, the percentage probability of ultimate failure is normally judged to be quite high. This judgmental percentage is multiplied by the leasehold acquisition cost, and that product is divided by the contractual period of the leasehold to determine a periodic leasehold impairment charge that is reported in exploration expense.

This judgmental probability percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favorable or unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment amortization expense is adjusted prospectively. At year-end 2017, the book value of the pools of property acquisition costs, that individually are relatively small and thus subject to the above-described periodic leasehold impairment calculation, was $503 million and the accumulated impairment reserve was $130 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 57 percent, and the weighted-average amortization period was approximately three years. If that judgmental percentage were to be raised by 5 percent across all calculations, before-tax leasehold impairment expense in 2018 would increase by approximately $6 million. At year-end 2017, the remaining $3,249 million of net capitalized unproved property costs consisted primarily of individually significant leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently being drilled, suspended exploratory wells, and capitalized interest. Of this amount, approximately $2.4 billion is concentrated in nine major development areas, the majority of which are not expected to move to proved properties in 2018. Management periodically assesses individually significant leaseholds for impairment based on the results of exploration and drilling efforts and the outlook for commercialization.

*Exploratory Costs*

For exploratory wells, drilling costs are temporarily capitalized, or "suspended," on the balance sheet, pending a determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort to justify development.

If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. The accounting notion of "sufficient progress" is a judgmental area, but the accounting rules do prohibit continued capitalization of suspended well costs on the expectation future market conditions will improve or new technologies will be found that would make the development economically profitable. Often, the ability to move into the development phase and record proved reserves is dependent on obtaining permits and government or co-venturer approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as we are actively pursuing such approvals and permits, and believe they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once a determination is made the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and reported in exploration expense.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as a dry hole when it determines the potential field does not warrant further investment in the near term. Criteria utilized in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected development costs, ability to apply existing technology to produce the reserves, fiscal terms, regulations or contract negotiations, and our expected return on investment.

At year-end 2017, total suspended well costs were $853 million, compared with $1,063 million at year-end 2016. For additional information on suspended wells, including an aging analysis, see Note 7—Suspended Wells and Other Exploration Expenses, in the Notes to Consolidated Financial Statements.

*Proved Reserves*

Engineering estimates of the quantities of proved reserves are inherently imprecise and represent only approximate amounts because of the judgments involved in developing such information. Reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processing yield factors, installed plant operating capacity and approved operating limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons.

Despite the inherent imprecision in these engineering estimates, accounting rules require disclosure of "proved" reserve estimates due to the importance of these estimates to better understand the perceived value and future cash flows of a company's operations. There are several authoritative guidelines regarding the engineering criteria that must be met before estimated reserves can be designated as "proved." Our geosciences and reservoir engineering organization has policies and procedures in place consistent with these authoritative guidelines. We have trained and experienced internal engineering personnel who estimate our proved reserves held by consolidated companies, as well as our share of equity affiliates.

Proved reserve estimates are adjusted annually in the fourth quarter and during the year if significant changes occur, and take into account recent production and subsurface information about each field. Also, as required by current authoritative guidelines, the estimated future date when an asset will be permanently shut down for economic reasons is based on 12-month average prices and current costs. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Generally, our proved reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to production sharing contracts, reported under the "economic interest" method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. We would expect reserves from these contracts to decrease when product prices rise and increase when prices decline.

The estimation of proved developed reserves also is important to the income statement because the proved developed reserve estimate for a field serves as the denominator in the unit-of-production calculation of the DD&A of the capitalized costs for that asset. At year-end 2017, the net book value of productive properties, plants and equipment (PP&E) subject to a unit-of-production calculation was approximately $41 billion and the DD&A recorded on these assets in 2017 was approximately $6.4 billion. The estimated proved developed reserves for our consolidated operations were 3.7 billion BOE at the end of 2016 and 3.0 billion BOE at the end of 2017. If the estimates of proved reserves used in the unit-of-production calculations had been lower by 10 percent across all calculations, before-tax DD&A in 2017 would have increased by an estimated $726 million.

**Impairments**

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. If there is an indication the carrying amount of an asset may not be recovered, the asset is monitored by management through an established process where changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted before-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for exploration and production assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of future production volumes, commodity prices, operating costs and capital decisions, considering all available information at the date of review. Differing assumptions could affect the timing and the amount of an impairment in any period. See Note 8—Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment when there is evidence of a loss in value and annually following updates to corporate planning assumptions. Such evidence of a loss in value might include our inability to recover the carrying amount, the lack of sustained earnings capacity which would justify the current investment amount, or a current fair value less than the investment's carrying amount. When it is determined such a loss in value is other than temporary, an impairment charge is recognized for the difference between the investment's carrying value and its estimated fair value. When determining whether a decline in value is other than temporary, management considers factors such as the length of time and extent of the decline, the investee's financial condition and near-term prospects, and our ability and intention to retain our investment for a period that will be sufficient to allow for any anticipated recovery in the market value of the investment. Since quoted market prices are usually not available, the fair value is typically based on the present value of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate. Differing assumptions could affect the timing and the amount of an impairment of an investment in any period. See the "APLNG" section of Note 5—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for additional information.

**Asset Retirement Obligations and Environmental Costs**

Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at operational sites. Our largest asset removal obligations involve plugging and abandonment of wells, removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska. The fair values of obligations for dismantling and removing these facilities are recorded as a liability and an increase to PP&E at the time of installation of the asset based on estimated discounted costs. Estimating future asset removal costs is difficult. Most of these removal obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. Asset removal technologies and costs, regulatory and other compliance considerations, expenditure timing, and other inputs into valuation of the obligation, including discount and inflation rates, are also subject to change.

Normally, changes in asset removal obligations are reflected in the income statement as increases or decreases to DD&A over the remaining life of the assets. However, for assets at or nearing the end of their operations, as well as previously sold assets for which we retained the asset removal obligation, an increase in the asset removal obligation can result in an immediate charge to earnings, because any increase in PP&E due to the increased obligation would immediately be subject to impairment, due to the low fair value of these properties.

In addition to asset removal obligations, under the above or similar contracts, permits and regulations, we have certain environmental-related projects. These are primarily related to remediation activities required by Canada and various states within the United States at exploration and production sites. Future environmental remediation costs are difficult to estimate because they are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. See Note 9—Asset Retirement Obligations and Accrued Environmental Costs, in the Notes to Consolidated Financial Statements, for additional information.

**Projected Benefit Obligations**

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations and company contribution requirements. For Employee Retirement Income Security Act-governed pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into the plans. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all vested benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Projected benefit obligations are particularly sensitive to the discount rate assumption. A 1 percent decrease in the discount rate assumption would increase projected benefit obligations by $1,200 million. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate assumption would increase annual benefit expense by $110 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $60 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans. We are also exposed to the possibility that lump sum retirement benefits taken from pension plans during the year could exceed the total of service and interest components of annual pension expense and trigger accelerated recognition of a portion of unrecognized net actuarial losses and gains. These benefit payments are based on decisions by plan participants and are therefore difficult to predict. In the event there is a significant reduction in the expected years of future service of present employees or elimination for a significant number of employees the accrual of defined benefits for some or all of their future services, we could recognize a curtailment gain or loss. See Note 17—Employee Benefit Plans, in the Notes to Consolidated Financial Statements, for additional information.

**Contingencies**

A number of claims and lawsuits are made against the company arising in the ordinary course of business. Management exercises judgment related to accounting and disclosure of these claims which includes losses, damages, and underpayments associated with environmental remediation, tax, contracts, and other legal disputes. As we learn new facts concerning contingencies, we reassess our position both with respect to amounts recognized and disclosed considering changes to the probability of additional losses and potential exposure. However, actual losses can and do vary from estimates for a variety of reasons including legal, arbitration, or other third-party decisions; settlement discussions; evaluation of scope of damages; interpretation of regulatory or contractual terms; expected timing of future actions; and proportion of liability shared with other responsible parties. Estimated future costs related to contingencies are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes. For additional information on contingent liabilities, see the “Contingencies” section within “Capital Resources and Liquidity.”

## CAUTIONARY STATEMENT FOR THE PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans, and objectives of management for future operations, are forward-looking statements. Examples of forward-looking statements contained in this report include our expected production growth and outlook on the business environment generally, our expected capital budget and capital expenditures, and discussions concerning future dividends. You can often identify our forward-looking statements by 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.

We based the forward-looking statements on our current expectations, estimates and projections about ourselves and the industries in which we operate in general. We caution you these statements are not guarantees of future performance as they involve assumptions that, while made in good faith, may prove to be incorrect, and involve risks and uncertainties we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including, but not limited to, the following:

- Fluctuations in crude oil, bitumen, natural gas, LNG and natural gas liquids prices, including a prolonged decline in these prices relative to historical or future expected levels.
- The impact of significant declines in prices for crude oil, bitumen, natural gas, LNG and natural gas liquids, which may result in recognition of impairment costs on our long-lived assets, leaseholds and nonconsolidated equity investments.
- Potential failures or delays in achieving expected reserve or production levels from existing and future oil and gas developments, including due to operating hazards, drilling risks and the inherent uncertainties in predicting reserves and reservoir performance.
- Reductions in reserves replacement rates, whether as a result of the significant declines in commodity prices or otherwise.
- Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.
- Unexpected changes in costs or technical requirements for constructing, modifying or operating exploration and production facilities.
- Legislative and regulatory initiatives addressing environmental concerns, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, bitumen, natural gas, LNG and natural gas liquids.
- Inability to timely obtain or maintain permits, including those necessary for construction, drilling and/or development; failure to comply with applicable laws and regulations; or inability to make capital expenditures required to maintain compliance with any necessary permits or applicable laws or regulations.
- Failure to complete definitive agreements and feasibility studies for, and to complete construction of, announced and future exploration and production and LNG development in a timely manner (if at all) or on budget.
- Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events, war, terrorism, cyber attacks, and information technology failures, constraints or disruptions.
- Changes in international monetary conditions and foreign currency exchange rate fluctuations.

- Reduced demand for our products or the use of competing energy products, including alternative energy sources.
- Substantial investment in and development of alternative energy sources, including as a result of existing or future environmental rules and regulations.
- Liability for remedial actions, including removal and reclamation obligations, under environmental regulations.
- Liability resulting from litigation.
- General domestic and international economic and political developments, including armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, bitumen, natural gas, LNG and natural gas liquids pricing, regulation or taxation; and other political, economic or diplomatic developments.
- Volatility in the commodity futures markets.
- Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business, including changes resulting from the implementation and interpretation of the Tax Cuts and Jobs Act.
- Competition in the oil and gas exploration and production industry.
- Any limitations on our access to capital or increase in our cost of capital related to illiquidity or uncertainty in the domestic or international financial markets.
- Our inability to execute, or delays in the completion, of any asset dispositions we elect to pursue.
- Potential failure to obtain, or delays in obtaining, any necessary regulatory approvals for asset dispositions or that such approvals may require modification to the terms of the transactions or the operation of our remaining business.
- Potential disruption of our operations as a result of asset dispositions, including the diversion of management time and attention.
- Our inability to deploy the net proceeds from any asset dispositions we undertake in the manner and timeframe we currently anticipate, if at all.
- Our inability to liquidate the common stock issued to us by Cenovus Energy as part of our sale of certain assets in western Canada at prices we deem acceptable, or at all.
- Our inability to obtain economical financing for development, construction or modification of facilities and general corporate purposes.
- The operation and financing of our joint ventures.
- The ability of our customers and other contractual counterparties to satisfy their obligations to us.
- Our inability to realize anticipated cost savings and expenditure reductions.
- The factors generally described in Item 1A—Risk Factors in our 2017 Annual Report on Form 10-K and any additional risks described in our other filings with the SEC.

## Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

### Financial Instrument Market Risk

We and certain of our subsidiaries hold and issue derivative contracts and financial instruments that expose our cash flows or earnings to changes in commodity prices, foreign currency exchange rates or interest rates. We may use financial and commodity-based derivative contracts to manage the risks produced by changes in the prices of natural gas, crude oil and related products; fluctuations in interest rates and foreign currency exchange rates; or to capture market opportunities.

Our use of derivative instruments is governed by an "Authority Limitations" document approved by our Board of Directors that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity. The Authority Limitations document also establishes the Value at Risk (VaR) limits for the company, and compliance with these limits is monitored daily. The Executive Vice President of Finance, Commercial, and Chief Financial Officer, who reports to the Chief Executive Officer, monitor commodity price risk and risks resulting from foreign currency exchange rates and interest rates. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, and monitors risks.

*Commodity Price Risk*

Our Commercial organization uses futures, forwards, swaps and options in various markets to accomplish the following objectives:

- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas consumers, to floating market prices.
- Enable us to use market knowledge to capture opportunities such as moving physical commodities to more profitable locations and storing commodities to capture seasonal or time premiums. We may use derivatives to optimize these activities.

We use a VaR model to estimate the loss in fair value that could potentially result on a single day from the effect of adverse changes in market conditions on the derivative financial instruments and derivative commodity instruments we hold or issue, including commodity purchases and sales contracts recorded on the balance sheet at December 31, 2017, as derivative instruments. Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes or held for purposes other than trading at December 31, 2017 and 2016, was immaterial to our consolidated cash flows and net income attributable to ConocoPhillips.

*Interest Rate Risk*

The following table provides information about our financial instruments that are sensitive to changes in U.S. interest rates. The debt portion of the table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on effective rates at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. The fair value of the fixed-rate financial instruments is estimated based on quoted market prices.

| | Millions of Dollars Except as Indicated | | | |
|---|---|---|---|---|
| | Debt | | | |
| Expected Maturity Date | Fixed Rate Maturity | Average Interest Rate | Floating Rate Maturity | Average Interest Rate |
| **Year-End 2017** | | | | |
| 2018 | **$ 2,250** | **3.31 %** | **$ 250** | **1.75 %** |
| 2019 | **23** | **-** | **-** | **-** |
| 2020 | **-** | **-** | **-** | **-** |
| 2021 | **150** | **9.13** | **-** | **-** |
| 2022 | **1,014** | **2.45** | **500** | **2.32** |
| Remaining years | **14,207** | **6.00** | **283** | **1.70** |
| Total | **$ 17,644** | | **$ 1,033** | |
| Fair value | **$ 21,402** | | **$ 1,033** | |
| | | | | |
| Year-End 2016 | | | | |
| 2017 | $ 1,001 | 1.06 % | $ - | - % |
| 2018 | 1,570 | 3.63 | 250 | 1.24 |
| 2019 | 2,250 | 5.75 | 1,450 | 2.31 |
| 2020 | 1,500 | 4.73 | - | - |
| 2021 | 2,150 | 4.08 | - | - |
| Remaining years | 15,221 | 5.77 | 783 | 1.43 |
| Total | $ 23,692 | | $ 2,483 | |
| Fair value | $ 26,824 | | $ 2,483 | |

*Foreign Currency Exchange Risk*
We have foreign currency exchange rate risk resulting from international operations. We do not comprehensively hedge the exposure to currency exchange rate changes although we may choose to selectively hedge certain foreign currency exchange rate exposures, such as firm commitments for capital projects or local currency tax payments, dividends and cash returns from net investments in foreign affiliates to be remitted within the coming year, and investments in available-for-sale securities.

At December 31, 2017 and 2016, we held foreign currency exchange forwards hedging cross-border commercial activity and foreign currency exchange swaps and options for purposes of mitigating our cash-related exposures. Although these forwards, swaps and options hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting. As a result, the change in the fair value of these foreign currency exchange derivatives is recorded directly in earnings.

At December 31, 2017, we had outstanding foreign currency zero-cost collars buying the right to sell $1.25 billion Canadian dollars (CAD) at $0.707 CAD and selling the right to buy $1.25 billion CAD at $0.842 CAD against the U.S. dollar. Based on the assumed volatility in the fair value calculation, the net fair value of these foreign currency contracts as at December 31, 2017, was a before-tax loss of $9 million. Based on an adverse hypothetical 10 percent change in the December 2017 exchange rate, this would result in an additional before-tax loss of $74 million. The sensitivity analysis is based on changing one assumption while holding all other assumptions constant, which in practice may be unlikely to occur, as changes in some of the assumptions may be correlated.

At December 31, 2016, we had outstanding foreign currency exchange forward-swap contracts. Since the gain or loss on the swaps was offset from remeasuring the related cash balances and since our aggregate position in the forwards was not material, there would have been no impact to our income from an adverse hypothetical 10 percent change in the December 2016 exchange rates.

The gross notional and fair market values of these positions at December 31, 2017 and 2016, were as follows:

| Foreign Currency Exchange Derivatives | | In Millions | | | |
|---|---|---|---|---|---|
| | | Notional* | | Fair Market Value** | |
| | | **2017** | 2016 | **2017** | 2016 |
| Sell U.S. dollar, buy Canadian dollar | USD | **-** | 13 | **-** | - |
| Buy U.S. dollar, sell British pound | USD | **-** | 25 | **-** | - |
| Sell Canadian dollar, buy U.S. dollar | CAD | **1,250** | - | **(9)** | - |
| Buy Canadian dollar, sell U.S. dollar | CAD | **25** | - | **1** | - |
| Buy British pound, sell Canadian dollar | GBP | **-** | 1,069 | **-** | (168) |
| Sell British pound, buy Norwegian krone | GBP | **-** | 51 | **-** | 1 |
| Sell British pound, buy Euro | GBP | **1** | - | **-** | - |

**Denominated in U.S. dollars (USD), British pound (GBP) and Canadian dollars (CAD).*
***Denominated in U.S. dollars.*

For additional information about our use of derivative instruments, see Note 13—Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

## Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### CONOCOPHILLIPS

### INDEX TO FINANCIAL STATEMENTS

## Report of Management

Management prepared, and is responsible for, the consolidated financial statements and the other information appearing in this annual report. The consolidated financial statements present fairly the company's financial position, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its consolidated financial statements, the company includes amounts that are based on estimates and judgments management believes are reasonable under the circumstances. The company's financial statements have been audited by Ernst & Young LLP, an independent registered public accounting firm appointed by the Audit and Finance Committee of the Board of Directors and ratified by stockholders. Management has made available to Ernst & Young LLP all of the company's financial records and related data, as well as the minutes of stockholders' and directors' meetings.

### Assessment of Internal Control Over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. ConocoPhillips' internal control system was designed to provide reasonable assurance to the company's management and directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2017. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework (2013)*. Based on our assessment, we believe the company's internal control over financial reporting was effective as of December 31, 2017.

Ernst & Young LLP has issued an audit report on the company's internal control over financial reporting as of December 31, 2017, and their report is included herein.

/s/ Ryan M. Lance

**Ryan M. Lance**
Chairman and
Chief Executive Officer

/s/ Don E. Wallette, Jr.

**Don E. Wallette, Jr.**
Executive Vice President, Finance,
Commercial and
Chief Financial Officer

February 20, 2018

## Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of ConocoPhillips

**Opinion on the Financial Statements**

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2017 and 2016, and the related consolidated income statement, consolidated statements of comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2017, and the related notes, condensed consolidating financial information listed in the Index at Item 8, and financial statement schedule listed in Item 15(a) (collectively referred to as the "financial statements"). In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of ConocoPhillips at December 31, 2017 and 2016, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), ConocoPhillips' internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 20, 2018, expressed an unqualified opinion thereon.

**Basis for Opinion**

These financial statements are the responsibility of ConocoPhillips' management. Our responsibility is to express an opinion on ConocoPhillips' financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to ConocoPhillips in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as ConocoPhillips' auditor since 1949.

Houston, Texas
February 20, 2018

## Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of ConocoPhillips

**Opinion on Internal Control over Financial Reporting**

We have audited ConocoPhillips' internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, ConocoPhillips maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets as of December 31, 2017 and 2016, and the related consolidated income statement, consolidated statements of comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2017, and the related notes, condensed consolidating financial information listed in the Index at Item 8, and financial statement schedule listed in Item 15(a) of ConocoPhillips and our report dated February 20, 2018, expressed an unqualified opinion thereon.

**Basis for Opinion**

ConocoPhillips' management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included under the heading "Assessment of Internal Control Over Financial Reporting" in the accompanying "Report of Management." Our responsibility is to express an opinion on ConocoPhillips' internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to ConocoPhillips in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

**Definition and Limitations of Internal Control Over Financial Reporting**

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

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

/s/ Ernst & Young LLP

Houston, Texas
February 20, 2018

| Years Ended December 31 | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| **Revenues and Other Income** | | | | |
| Sales and other operating revenues | **$** | **29,106** | 23,693 | 29,564 |
| Equity in earnings of affiliates | | **772** | 52 | 655 |
| Gain on dispositions | | **2,177** | 360 | 591 |
| Other income | | **529** | 255 | 125 |
| Total Revenues and Other Income | | **32,584** | 24,360 | 30,935 |
| **Costs and Expenses** | | | | |
| Purchased commodities | | **12,475** | 9,994 | 12,426 |
| Production and operating expenses | | **5,173** | 5,667 | 7,016 |
| Selling, general and administrative expenses | | **561** | 723 | 953 |
| Exploration expenses | | **938** | 1,915 | 4,192 |
| Depreciation, depletion and amortization | | **6,845** | 9,062 | 9,113 |
| Impairments | | **6,601** | 139 | 2,245 |
| Taxes other than income taxes | | **809** | 739 | 901 |
| Accretion on discounted liabilities | | **362** | 425 | 483 |
| Interest and debt expense | | **1,098** | 1,245 | 920 |
| Foreign currency transaction (gains) losses | | **35** | (19) | (75) |
| Other expense | | **302** | - | - |
| Total Costs and Expenses | | **35,199** | 29,890 | 38,174 |
| Loss before income taxes | | **(2,615)** | (5,530) | (7,239) |
| Income tax benefit | | **(1,822)** | (1,971) | (2,868) |
| Net loss | | **(793)** | (3,559) | (4,371) |
| Less: net income attributable to noncontrolling interests | | **(62)** | (56) | (57) |
| **Net Loss Attributable to ConocoPhillips** | **$** | **(855)** | (3,615) | (4,428) |
| **Net Loss Attributable to ConocoPhillips Per Share of Common Stock** *(dollars)* | | | | |
| Basic | **$** | **(0.70)** | (2.91) | (3.58) |
| Diluted | | **(0.70)** | (2.91) | (3.58) |
| **Dividends Paid Per Share of Common Stock** *(dollars)* | **$** | **1.06** | 1.00 | 2.94 |
| **Average Common Shares Outstanding** *(in thousands)* | | | | |
| Basic | | **1,221,038** | 1,245,440 | 1,241,919 |
| Diluted | | **1,221,038** | 1,245,440 | 1,241,919 |

*See Notes to Consolidated Financial Statements.*

## Consolidated Statement of Comprehensive Income **ConocoPhillips**

| Years Ended December 31 | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| **Net Loss** | $ | **(793)** | (3,559) | (4,371) |
| Other comprehensive income (loss) | | | | |
| Defined benefit plans | | | | |
| Prior service credit arising during the period | | **2** | 23 | 301 |
| Reclassification adjustment for amortization of prior service credit included in net loss | | **(38)** | (35) | (19) |
| Net change | | **(36)** | (12) | 282 |
| Net actuarial gain (loss) arising during the period | | **19** | (481) | 592 |
| Reclassification adjustment for amortization of net actuarial losses included in net loss | | **247** | 309 | 403 |
| Net change | | **266** | (172) | 995 |
| Nonsponsored plans* | | **(2)** | 2 | 1 |
| Income taxes on defined benefit plans | | **(81)** | 78 | (460) |
| Defined benefit plans, net of tax | | **147** | (104) | 818 |
| Unrealized holding loss on securities | | **(58)** | - | - |
| Unrealized loss on securities, net of tax | | **(58)** | - | - |
| Foreign currency translation adjustments | | **586** | 153 | (5,199) |
| Reclassification adjustment for gain included in net loss | | **-** | 5 | - |
| Income taxes on foreign currency translation adjustments | | **-** | - | 36 |
| Foreign currency translation adjustments, net of tax | | **586** | 158 | (5,163) |
| **Other Comprehensive Income (Loss), Net of Tax** | | **675** | 54 | (4,345) |
| **Comprehensive Loss** | | **(118)** | (3,505) | (8,716) |
| Less: comprehensive income attributable to noncontrolling interests | | **(62)** | (56) | (57) |
| **Comprehensive Loss Attributable to ConocoPhillips** | $ | **(180)** | (3,561) | (8,773) |

**Plans for which ConocoPhillips is not the primary obligor—primarily those administered by equity affiliates.*
*See Notes to Consolidated Financial Statements.*

| **Consolidated Balance Sheet** | | | **ConocoPhillips** |
|---|---|---|---|
| At December 31 | | Millions of Dollars | |
| | | **2017** | 2016 |
| **Assets** | | | |
| Cash and cash equivalents | $ | **6,325** | 3,610 |
| Short-term investments | | **1,873** | 50 |
| Accounts and notes receivable (net of allowance of $4 million in 2017 and $5 million in 2016) | | **4,179** | 3,249 |
| Accounts and notes receivable—related parties | | **141** | 165 |
| Investment in Cenovus Energy | | **1,899** | - |
| Inventories | | **1,060** | 1,018 |
| Prepaid expenses and other current assets | | **1,035** | 517 |
| Total Current Assets | | **16,512** | 8,609 |
| Investments and long-term receivables | | **9,599** | 21,091 |
| Loans and advances—related parties | | **461** | 581 |
| Net properties, plants and equipment (net of accumulated depreciation, depletion and amortization of $64,748 million in 2017 and $73,075 million in 2016) | | **45,683** | 58,331 |
| Other assets | | **1,107** | 1,160 |
| Total Assets | $ | **73,362** | 89,772 |
| | | | |
| **Liabilities** | | | |
| Accounts payable | $ | **4,009** | 3,631 |
| Accounts payable—related parties | | **21** | 22 |
| Short-term debt | | **2,575** | 1,089 |
| Accrued income and other taxes | | **1,038** | 484 |
| Employee benefit obligations | | **725** | 689 |
| Other accruals | | **1,029** | 994 |
| Total Current Liabilities | | **9,397** | 6,909 |
| Long-term debt | | **17,128** | 26,186 |
| Asset retirement obligations and accrued environmental costs | | **7,631** | 8,425 |
| Deferred income taxes | | **5,282** | 8,949 |
| Employee benefit obligations | | **1,854** | 2,552 |
| Other liabilities and deferred credits | | **1,269** | 1,525 |
| Total Liabilities | | **42,561** | 54,546 |
| | | | |
| **Equity** | | | |
| Common stock (2,500,000,000 shares authorized at $.01 par value) | | | |
| Issued (2017—1,785,419,175 shares; 2016—1,782,079,107 shares) | | | |
| Par value | | **18** | 18 |
| Capital in excess of par | | **46,622** | 46,507 |
| Treasury stock (at cost: 2017—608,312,034 shares; 2016—544,809,771 shares) | | **(39,906)** | (36,906) |
| Accumulated other comprehensive loss | | **(5,518)** | (6,193) |
| Retained earnings | | **29,391** | 31,548 |
| Total Common Stockholders' Equity | | **30,607** | 34,974 |
| Noncontrolling interests | | **194** | 252 |
| Total Equity | | **30,801** | 35,226 |
| Total Liabilities and Equity | $ | **73,362** | 89,772 |

*See Notes to Consolidated Financial Statements.*

## Consolidated Statement of Cash Flows **ConocoPhillips**

| Years Ended December 31 | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| **Cash Flows From Operating Activities** | | | | |
| Net loss | **$** | **(793)** | (3,559) | (4,371) |
| Adjustments to reconcile net loss to net cash provided by operating activities | | | | |
| Depreciation, depletion and amortization | | **6,845** | 9,062 | 9,113 |
| Impairments | | **6,601** | 139 | 2,245 |
| Dry hole costs and leasehold impairments | | **566** | 1,184 | 3,065 |
| Accretion on discounted liabilities | | **362** | 425 | 483 |
| Deferred taxes | | **(3,681)** | (2,221) | (2,772) |
| Undistributed equity earnings | | **(232)** | 299 | 101 |
| Gain on dispositions | | **(2,177)** | (360) | (591) |
| Other | | **(429)** | (85) | 321 |
| Working capital adjustments | | | | |
| Decrease (increase) in accounts and notes receivable | | **(886)** | 820 | 1,810 |
| Decrease (increase) in inventories | | **(55)** | 44 | 166 |
| Decrease in prepaid expenses and other current assets | | **69** | 105 | 239 |
| Increase (decrease) in accounts payable | | **265** | (524) | (1,647) |
| Increase (decrease) in taxes and other accruals | | **622** | (926) | (590) |
| Net Cash Provided by Operating Activities | | **7,077** | 4,403 | 7,572 |
| | | | | |
| **Cash Flows From Investing Activities** | | | | |
| Capital expenditures and investments | | **(4,591)** | (4,869) | (10,050) |
| Working capital changes associated with investing activities | | **132** | (331) | (968) |
| Proceeds from asset dispositions | | **13,860** | 1,286 | 1,952 |
| Net purchases of short-term investments | | **(1,790)** | (51) | - |
| Collection of advances/loans—related parties | | **115** | 108 | 105 |
| Other | | **36** | (2) | 306 |
| Net Cash Provided by (Used in) Investing Activities | | **7,762** | (3,859) | (8,655) |
| | | | | |
| **Cash Flows From Financing Activities** | | | | |
| Issuance of debt | | **-** | 4,594 | 2,498 |
| Repayment of debt | | **(7,876)** | (2,251) | (103) |
| Issuance of company common stock | | **(63)** | (63) | (82) |
| Repurchase of company common stock | | **(3,000)** | (126) | - |
| Dividends paid | | **(1,305)** | (1,253) | (3,664) |
| Other | | **(112)** | (137) | (78) |
| Net Cash Provided by (Used in) Financing Activities | | **(12,356)** | 764 | (1,429) |
| | | | | |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | | **232** | (66) | (182) |
| | | | | |
| **Net Change in Cash and Cash Equivalents** | | **2,715** | 1,242 | (2,694) |
| Cash and cash equivalents at beginning of period | | **3,610** | 2,368 | 5,062 |
| Cash and Cash Equivalents at End of Period | **$** | **6,325** | 3,610 | 2,368 |

*See Notes to Consolidated Financial Statements.*

## Consolidated Statement of Changes in Equity

**ConocoPhillips**

| | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Attributable to ConocoPhillips | | | | | | | |
| | Common Stock | | | | | | | |
| | Par Value | Capital in Excess of Par | Treasury Stock | Accum. Other Comprehensive Income (Loss) | Retained Earnings | Non-Controlling Interests | Total |
| December 31, 2014 | $ | 18 | 46,071 | (36,780) | (1,902) | 44,504 | 362 | 52,273 |
| Net income (loss) | | | | | | (4,428) | 57 | (4,371) |
| Other comprehensive loss | | | | | (4,345) | | | (4,345) |
| Dividends paid | | | | | | (3,664) | | (3,664) |
| Distributions to noncontrolling interests and other | | | | | | | (100) | (100) |
| Distributed under benefit plans | | | 286 | | | | | 286 |
| Other | | | | | | 2 | 1 | 3 |
| December 31, 2015 | $ | 18 | 46,357 | (36,780) | (6,247) | 36,414 | 320 | 40,082 |
| Net income (loss) | | | | | | (3,615) | 56 | (3,559) |
| Other comprehensive income | | | | | 54 | | | 54 |
| Dividends paid | | | | | | (1,253) | | (1,253) |
| Repurchase of company common stock | | | | (126) | | | | (126) |
| Distributions to noncontrolling interests and other | | | | | | | (124) | (124) |
| Distributed under benefit plans | | | 150 | | | | | 150 |
| Other | | | | | | 2 | | 2 |
| December 31, 2016 | $ | 18 | 46,507 | (36,906) | (6,193) | 31,548 | 252 | 35,226 |
| Net income (loss) | | | | | | **(855)** | **62** | **(793)** |
| Other comprehensive income | | | | | **675** | | | **675** |
| Dividends paid | | | | | | **(1,305)** | | **(1,305)** |
| Repurchase of company common stock | | | | **(3,000)** | | | | **(3,000)** |
| Distributions to noncontrolling interests and other | | | | | | | **(120)** | **(120)** |
| Distributed under benefit plans | | | **115** | | | | | **115** |
| Other | | | | | | **3** | | **3** |
| **December 31, 2017** | **$** | **18** | **46,622** | **(39,906)** | **(5,518)** | **29,391** | **194** | **30,801** |

*See Notes to Consolidated Financial Statements.*

## Note 1—Accounting Policies

- **Consolidation Principles and Investments**—Our consolidated financial statements include the accounts of majority-owned, controlled subsidiaries and variable interest entities where we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we have the ability to exert significant influence over the affiliates' operating and financial policies. When we do not have the ability to exert significant influence, the investment is either classified as available-for-sale if fair value is readily determinable, or the cost method is used if fair value is not readily determinable. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants and terminals are consolidated on a proportionate basis. Other securities and investments are generally carried at cost.

  We manage our operations through six operating segments, defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International. For additional information, see Note 23—Segment Disclosures and Related Information.

- **Foreign Currency Translation**—Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in accumulated other comprehensive income in common stockholders' equity. Foreign currency transaction gains and losses are included in current earnings. Most of our foreign operations use their local currency as the functional currency.

- **Use of Estimates**—The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from these estimates.

- **Revenue Recognition**—Revenues associated with sales of crude oil, bitumen, natural gas, liquefied natural gas (LNG), natural gas liquids and other items are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, either immediately or within a fixed delivery schedule that is reasonable and customary in the industry.

  Revenues associated with producing properties in which we have an interest with other producers are recognized based on the actual volumes we sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, which are deemed to be nonrecoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are generally not significant.

  Revenues associated with transactions commonly called buy/sell contracts, in which the purchase and sale of inventory with the same counterparty are entered into "in contemplation" of one another, are combined and reported net (i.e., on the same income statement line).

- **Shipping and Handling Costs**—We include shipping and handling costs in production and operating expenses for production activities. Transportation costs related to marketing activities are recorded in purchased commodities. Freight costs billed to customers are recorded as a component of revenue.

- **Cash Equivalents**—Cash equivalents are highly liquid, short-term investments that are readily convertible to known amounts of cash and have original maturities of 90 days or less from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.

- **Short-Term Investments**—Investments in bank time deposits and marketable securities (commercial paper and government obligations) with original maturities of greater than 90 days but less than one year are classified as short-term investments.

- **Inventories**—We have several valuation methods for our various types of inventories and consistently use the following methods for each type of inventory. Our commodity-related inventories are recorded at cost primarily using the last-in, first-out (LIFO) basis. We measure these inventories at the lower-of-cost-or-market in the aggregate. Any necessary lower-of-cost-or-market write-downs at year end are recorded as permanent adjustments to the LIFO cost basis. LIFO is used to better match current inventory costs with current revenues. Costs include both direct and indirect expenditures incurred in bringing an item or product to its existing condition and location, but not unusual/nonrecurring costs or research and development costs. Materials, supplies and other miscellaneous inventories, such as tubular goods and well equipment, are valued using various methods, including the weighted-average-cost method, and the first-in, first-out (FIFO) method, consistent with industry practice.

- **Fair Value Measurements**—Assets and liabilities measured at fair value and required to be categorized within the fair value hierarchy are categorized into one of three different levels depending on the observability of the inputs employed in the measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1 for the asset or liability, either directly or indirectly through market-corroborated inputs. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or our assumptions about pricing by market participants.

- **Derivative Instruments**—Derivative instruments are recorded on the balance sheet at fair value. If the right of offset exists and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the balance sheet and the collateral payable or receivable is netted against derivative assets and derivative liabilities, respectively.

  Recognition and classification of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives not accounted for as hedges are recognized immediately in earnings.

- **Oil and Gas Exploration and Development**—Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

  **Property Acquisition Costs**—Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption properties, plants and equipment (PP&E). Leasehold impairment is recognized based on exploratory experience and management's judgment. Upon achievement of all conditions necessary for reserves to be classified as proved, the associated leasehold costs are reclassified to proved properties.

  **Exploratory Costs**—Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized, or "suspended," on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas resources are designated as proved reserves.

  Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as dry holes when it judges the potential field does not warrant further investment in the near term. See Note 7—Suspended Wells and Other Exploration Expenses, for additional information on suspended wells.

**Development Costs**—Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

**Depletion and Amortization**—Leasehold costs of producing properties are depleted using the unit-of-production method based on estimated proved oil and gas reserves. Amortization of intangible development costs is based on the unit-of-production method using estimated proved developed oil and gas reserves.

- **Capitalized Interest**—Interest from external borrowings is capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets.

- **Depreciation and Amortization**—Depreciation and amortization of PP&E on producing hydrocarbon properties and certain pipeline assets (those which are expected to have a declining utilization pattern), are determined by the unit-of-production method. Depreciation and amortization of all other PP&E are determined by either the individual-unit-straight-line method or the group-straight-line method (for those individual units that are highly integrated with other units).

- **Impairment of Properties, Plants and Equipment**—PP&E used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. If there is an indication the carrying amount of an asset may not be recovered, the asset is monitored by management through an established process where changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted before-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value through additional amortization or depreciation provisions and reported as impairments in the periods in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for exploration and production assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell, with fair value determined using a binding negotiated price, if available, or present value of expected future cash flows as previously described.

  The expected future cash flows used for impairment reviews and related fair value calculations are based on estimated future production volumes, prices and costs, considering all available evidence at the date of review. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. Additionally, when probable and possible reserves exist, an appropriate risk-adjusted amount of these reserves may be included in the impairment calculation.

- **Impairment of Investments in Nonconsolidated Entities**—Investments in nonconsolidated entities are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred and annually following updates to corporate planning assumptions. When such a condition is judgmentally determined to be other than temporary, the carrying value of the investment is written down to fair value. The fair value of the impaired investment is based on quoted market prices, if available, or upon the present value of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate.

- **Maintenance and Repairs**—Costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

- **Property Dispositions**—When complete units of depreciable property are sold, the asset cost and related accumulated depreciation are eliminated, with any gain or loss reflected in the "Gain on dispositions" line of our consolidated income statement. When less than complete units of depreciable property are disposed of or retired, the difference between asset cost and salvage value is charged or credited to accumulated depreciation.

- **Asset Retirement Obligations and Environmental Costs**—The fair value of legal obligations to retire and remove long-lived assets are recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time the liability is increased for the change in its present value, and the capitalized cost in PP&E is depreciated over the useful life of the related asset. For additional information, see Note 9—Asset Retirement Obligations and Accrued Environmental Costs.

  Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures relating to an existing condition caused by past operations, and those having no future economic benefit, are expensed. Liabilities for environmental expenditures are recorded on an undiscounted basis (unless acquired in a purchase business combination, which we record on a discounted basis) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is probable and estimable.

- **Guarantees**—The fair value of a guarantee is determined and recorded as a liability at the time the guarantee is given. The initial liability is subsequently reduced as we are released from exposure under the guarantee. We amortize the guarantee liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of guarantee. In cases where the guarantee term is indefinite, we reverse the liability when we have information indicating the liability is essentially relieved or amortize it over an appropriate time period as the fair value of our guarantee exposure declines over time. We amortize the guarantee liability to the related income statement line item based on the nature of the guarantee. When it becomes probable that we will have to perform on a guarantee, we accrue a separate liability if it is reasonably estimable, based on the facts and circumstances at that time. We reverse the fair value liability only when there is no further exposure under the guarantee.

- **Share-Based Compensation**—We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award) or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. We have elected to recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

- **Income Taxes**—Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial reporting basis and the tax basis of our assets and liabilities, except for deferred taxes on income and temporary differences related to the cumulative translation adjustment considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures. Allowable tax credits are applied currently as reductions of the provision for income taxes. Interest related to unrecognized tax benefits is reflected in interest and debt expense, and penalties related to unrecognized tax benefits are reflected in production and operating expenses.

- **Taxes Collected from Customers and Remitted to Governmental Authorities**—Sales and value-added taxes are recorded net.

- **Net Income (Loss) Per Share of Common Stock**—Basic net income (loss) per share of common stock is calculated based upon the daily weighted-average number of common shares outstanding during the year. Also, this calculation includes fully vested stock and unit awards that have not yet been issued as common stock, along with an adjustment to net income (loss) for dividend equivalents paid on unvested unit awards that are considered participating securities. Diluted net income per share of common stock includes unvested stock, unit or option awards granted under our compensation plans and vested but unexercised stock options, but only to the extent these instruments dilute net income per share, primarily under the treasury-stock method. Diluted net loss per share, which is calculated the same as basic net loss per share, does not assume conversion or exercise of securities that would have an antidilutive effect. Treasury stock is excluded from the daily weighted-average number of common shares outstanding in both calculations. The earnings per share impact of the participating securities is immaterial.

## Note 2—Variable Interest Entities (VIEs)

We hold variable interests in VIEs that have not been consolidated because we are not considered the primary beneficiary. Information on our significant VIEs follows:

### Australia Pacific LNG Pty Ltd (APLNG)

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary of APLNG because we share with Origin Energy and China Petrochemical Corporation (Sinopec) the power to direct the key activities of APLNG that most significantly impact its economic performance, which involve activities related to the production and commercialization of coalbed methane, as well as LNG processing and export marketing. As a result, we do not consolidate APLNG, and it is accounted for as an equity method investment.

As of December 31, 2017, we have not provided any financial support to APLNG other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of APLNG. See Note 5—Investments, Loans and Long-Term Receivables, and Note 11—Guarantees, for additional information.

### Marine Well Containment Company, LLC (MWCC)

MWCC provides well containment equipment and technology and related services in the deepwater U.S. Gulf of Mexico. Its principal activities involve the development and maintenance of rapid-response hydrocarbon well containment systems that are deployable in the Gulf of Mexico on a call-out basis. We have a 10 percent ownership interest in MWCC, and it is accounted for as an equity method investment because MWCC is a limited liability company in which we are a Founding Member and exercise significant influence through our permanent seat on the ten-member Executive Committee responsible for overseeing the affairs of MWCC. In 2016, MWCC executed a $154 million term loan financing arrangement with an external financial institution whose terms required the financing be secured by letters of credit provided by certain owners of MWCC, including ConocoPhillips. In connection with the financing transaction, we issued a letter of credit of $22 million which can be drawn upon in the event of a default by MWCC on its obligation to repay the proceeds of the term loan. The fair value of this letter of credit is immaterial and not recognized on our consolidated balance sheet. MWCC is considered a VIE, as it has entered into arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary and do not consolidate MWCC because we share the power to govern the business and operation of the company and to undertake certain obligations that most significantly impact its economic performance with nine other unaffiliated owners of MWCC.

At December 31, 2017, the book value of our equity method investment in MWCC was $139 million. We have not provided any financial support to MWCC other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of MWCC.

## Note 3—Inventories

Inventories at December 31 were:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2017** | 2016 |
| Crude oil and natural gas | $ | **512** | 418 |
| Materials and supplies | | **548** | 600 |
| | $ | **1,060** | 1,018 |

Inventories valued on the LIFO basis totaled $341 million and $269 million at December 31, 2017 and 2016, respectively. The estimated excess of current replacement cost over LIFO cost of inventories was approximately $124 million and $104 million at December 31, 2017 and December 31, 2016, respectively. In 2017, liquidation of LIFO inventory values increased the net loss attributable to ConocoPhillips by $1 million.

## Note 4—Assets Held for Sale, Sold or Acquired

### Assets Held for Sale

In the second quarter of 2017, we signed a definitive agreement to sell our interest in the Barnett. We terminated this agreement in the fourth quarter of 2017 and are continuing to market the asset in 2018. In connection with the signing of the definitive agreement, we recorded a before-tax impairment of $572 million to reduce the carrying value of our investment to estimated fair value. As of December 31, 2017, our Barnett interests had a net carrying value of approximately $291 million and were considered held for sale resulting in the reclassification of $339 million of PP&E to "Prepaid expenses and other current assets" and $48 million of noncurrent liabilities, primarily asset retirement obligations (ARO), to "Other accruals" on our consolidated balance sheet. The before-tax loss associated with our interests in the Barnett, including the $572 million impairment noted above, was $566 million, $66 million, and $58 million for the years ended December 31, 2017, 2016 and 2015, respectively. The Barnett results of operations are reported within our Lower 48 segment.

In addition to the Barnett, certain other properties in our Lower 48 segment met the criteria for assets held for sale at December 31, 2017. These properties had a net carrying value of approximately $212 million after recording a before-tax impairment of $78 million to reduce the carrying value to estimated fair value in the fourth quarter of 2017. We reclassified $238 million of PP&E to "Prepaid expenses and other current assets" and $26 million of noncurrent liabilities, primarily AROs, to "Other accruals" on our consolidated balance sheet. In January 2018, we completed the sale of a portion of these properties for net proceeds of $112 million.

### Assets Sold

All gains or losses are reported before-tax and are included net in the "Gain on dispositions" line on our consolidated income statement. All cash proceeds are included in the "Cash Flows From Investing Activities" section of our consolidated statement of cash flows.

*2017*

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the Foster Creek Christina Lake (FCCL) Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction was $11.0 billion in cash after customary adjustments, 208 million Cenovus Energy common shares and a five-year uncapped contingent payment. The value of the shares at closing was $1.96 billion based on a price of $9.41 per share on the New York Stock Exchange. The contingent payment, calculated and paid on a quarterly basis, is $6 million Canadian dollars (CAD) for every $1 CAD by which the Western Canada Select (WCS) quarterly average crude price exceeds $52 CAD per barrel.

At closing, the carrying value of our equity investment in FCCL was $8.9 billion. The carrying value of our interest in the western Canada gas assets was $1.9 billion consisting primarily of $2.6 billion of PP&E, partly offset by AROs of $585 million and approximately $100 million of environmental and other accruals. A before-tax gain of $2.1 billion was included in the "Gain on disposition" line on our consolidated income statement in 2017. We reported before-tax losses of $26 million, $572 million and $582 million for the western Canada gas producing properties for the years ended December 31, 2017, 2016 and 2015, respectively. We reported before-tax equity earnings of $197 million, $89 million and $78 million for FCCL for the same periods, respectively. Both FCCL and the western Canada gas assets were reported within our Canada segment.

For more information on the Canada disposition and our investment in Cenovus Energy see Note 6—Investment in Cenovus Energy, Note 14—Fair Value Measurement, and Note 19—Accumulated Other Comprehensive Loss.

On July 31, 2017, we completed the sale of our interests in the San Juan Basin to an affiliate of Hilcorp Energy Company for $2.5 billion in cash after customary adjustments, and recognized a loss on disposition of $22 million. The transaction includes a contingent payment of up to $300 million. The six-year contingent payment, effective beginning January 1, 2018, is due annually for the periods in which the monthly U.S. Henry Hub price is at or above $3.20 per million British thermal units.

In the second quarter of 2017, we recorded a before-tax impairment of $3.3 billion to reduce the carrying value of our interests in the San Juan Basin to fair value. At the time of disposition, the San Juan Basin interests had a net carrying value of approximately $2.5 billion, consisting of $2.9 billion of PP&E and $406 million of liabilities, primarily AROs. The before-tax loss associated with our interests in the San Juan Basin, including both the $3.3 billion impairment and $22 million loss on disposition noted above, was $3.2 billion, $239 million and $99 million for the years ended December 31, 2017, 2016 and 2015, respectively. The San Juan Basin results of operations were reported within our Lower 48 segment.

On September 29, 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments, and recognized a before-tax loss on disposition of $28 million. At the time of the disposition, the carrying value of our interest was $206 million, consisting primarily of $279 million of PP&E and $72 million of AROs. Including the $28 million loss on disposition noted above, we reported before-tax losses for the Panhandle properties of $14 million, $21 million, and $41 million for the years ended December 31, 2017, 2016 and 2015, respectively. The Panhandle results were reported within our Lower 48 segment.

*2016*

In April 2016, we sold our interest in the Alaska Beluga River Unit natural gas field in the Cook Inlet for $134 million, net of settlement of gas imbalances and customary adjustments, and recognized a gain on disposition of $56 million. At the time of disposition, the net carrying value of our Beluga River Unit interest, which was included in the Alaska segment, was $78 million, consisting primarily of $100 million of PP&E and $19 million of AROs.

In October 2016, we completed an asset exchange with Bonavista Energy in which we gave up approximately 141,000 net acres of noncore developed properties in central Alberta in exchange for approximately 40,000 net acres of primarily undeveloped properties in northeast British Columbia. The fair value of the transaction was determined to be approximately $69 million and a before-tax impairment of $57 million was recognized in the third quarter of 2016 when the assets were considered held for sale, to reduce the carrying value to fair value. A loss on disposition of approximately $1 million was recognized upon completion of the transaction. The divested properties were included in the Canada segment.

Also in October 2016, we sold ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal for $442 million and recognized a gain on disposition of $146 million. At the time of disposition, the carrying value of our interest was $286 million, which was primarily PP&E. Senegal results of operations were reported within our Other International segment.

In November 2016, we completed the sale of our 40 percent interest in South Natuna Sea Block B for $225 million and recognized a loss on disposition of $26 million. Our interest in Block B was included in the Asia Pacific and Middle East segment. In 2016, we recognized a before-tax impairment of $42 million at the time it was considered held for sale to reduce the carrying value to fair value. At the time of the disposition, the carrying value of our interest was approximately $251 million, which included primarily $154 million of PP&E, $178 million of accounts receivable, $25 million of inventory, $54 million of deferred tax assets, $130 million of accounts payable and other accruals, and $38 million of employee benefit obligations.

In December 2016, we completed the sale of certain mineral and non-mineral fee lands in northeastern Minnesota, which were included in the Lower 48 segment, for $148 million and recorded a gain on disposition of $4 million. The majority of the assets sold were acquired during the fourth quarter of 2016 as a result of ConocoPhillips holding a reversionary interest in the Greater Northern Iron Ore Properties Trust (the Trust), a grantor trust that owned mineral and surface interests in the Mesabi Iron Range in northeastern Minnesota and certain other personal property. Pursuant to the terms of the Trust Agreement, the Trust terminated on April 6, 2015. In November 2016, upon completion of the wind-down period, documents memorializing ConocoPhillips' ownership of certain Trust property, including all of the Trust's mineral properties and active leases, were delivered to us and we recognized the fair value of the net assets resulting in a gain of $88 million recorded in the "Other income" line on our consolidated income statement. At the time of the disposition, the carrying value of our interests, which included the assets obtained from the Trust, consisted of $144 million of PP&E.

*2015*

In November 2015, we sold a portion of our western Canadian properties located in British Columbia, Alberta, and Saskatchewan for $198 million and recognized a gain on disposition of $66 million. At the time of the disposition, the carrying value of our interest, which was included in the Canada segment, was $132 million, which included primarily $379 million of PP&E and $248 million of ARO.

In December 2015, we sold a portion of our western Canadian properties located in central Alberta for $130 million and recognized a loss on disposition of $235 million. At the time of the disposition, the carrying value of our interest, which was included in the Canada segment, was approximately $365 million, which included primarily $488 million of PP&E and $126 million of ARO.

Additionally, other December 2015 disposition transactions are summarized below.

We sold producing properties in East Texas and North Louisiana for $412 million and recognized a gain on disposition of $189 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $223 million, which included $351 million of PP&E and $128 million of ARO.

We sold certain gas producing properties in South Texas for $358 million and recognized a gain on disposition of $201 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $157 million, which included $369 million of PP&E and $212 million of ARO.

We sold certain pipeline and gathering assets in South Texas for $201 million and recognized a gain on disposition of $193 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $8 million, which primarily included $24 million of PP&E and $18 million of ARO.

We also sold our 50 percent interest in the Russian joint venture, Polar Lights Company, for $98 million and recognized a gain on disposition of $58 million. At the time of the disposition, the carrying value of our equity method investment in Polar Lights Company, which was included in our Other International segment, was approximately $40 million.

**Acquisition**
In January 2018, we entered into an agreement to acquire certain oil and gas assets in Alaska for $400 million, subject to customary adjustments. The acquisition is subject to regulatory approval.

**Note 5—Investments, Loans and Long-Term Receivables**

Components of investments, loans and long-term receivables at December 31 were:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2017** | 2016 |
| Equity investments | $ | **9,129** | 20,364 |
| Loans and advances—related parties | | **461** | 581 |
| Long-term receivables | | **375** | 631 |
| Other investments | | **95** | 96 |
| | $ | **10,060** | 21,672 |

**Equity Investments**
Affiliated companies in which we had a significant equity investment at December 31, 2017, included:

- APLNG—37.5 percent owned joint venture with Origin Energy (37.5 percent) and Sinopec (25 percent)—to develop coalbed methane production from the Bowen and Surat basins in Queensland, Australia, as well as process and export LNG.
- Qatar Liquefied Gas Company Limited (3) (QG3)—30 percent owned joint venture with affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent)—produces and liquefies natural gas from Qatar's North Field, as well as exports LNG.

Summarized 100 percent earnings information for equity method investments in affiliated companies, combined, was as follows:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| Revenues | $ | **11,554** | 10,149 | 11,003 |
| Income (loss) before income taxes | | **(2,875)** | 660 | 1,866 |
| Net income (loss) | | **(1,431)** | 799 | 1,801 |

Summarized 100 percent balance sheet information for equity method investments in affiliated companies, combined, was as follows:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2017** | 2016 |
| Current assets | $ | **2,920** | 3,578 |
| Noncurrent assets | | **42,693** | 60,243 |
| Current liabilities | | **2,453** | 2,352 |
| Noncurrent liabilities | | **25,522** | 23,764 |

Our share of income taxes incurred directly by an equity company is reported in equity in earnings of affiliates, and as such is not included in income taxes in our consolidated financial statements.

At December 31, 2017, retained earnings included $20 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $605 million, $398 million and $876 million in 2017, 2016 and 2015, respectively.

**APLNG**

APLNG is focused on coalbed methane production from the Bowen and Surat basins in Queensland, Australia, to supply the domestic gas market and on LNG processing and export sales. Our investment in APLNG gives us access to coalbed methane resources in Australia and enhances our LNG position. The majority of APLNG LNG is sold under two long-term sales and purchase agreements, supplemented with sales of additional LNG spot cargoes targeting the Asia Pacific markets. Origin Energy, an integrated Australian energy company, is the operator of APLNG's production and pipeline system, while we operate the LNG facility.

APLNG executed project financing agreements for an $8.5 billion project finance facility in 2012. The $8.5 billion project finance facility is composed of financing agreements executed by APLNG with the Export-Import Bank of the United States for approximately $2.9 billion, the Export-Import Bank of China for approximately $2.7 billion, and a syndicate of Australian and international commercial banks for approximately $2.9 billion. At December 31, 2017, all amounts have been drawn from the facility. APLNG made its first principal and interest repayment in March 2017, and will continue to make bi-annual payments until March 2029. At December 31, 2017, a balance of $7.9 billion was outstanding on the facility. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility until the project achieves financial completion. In October 2016, we reached financial completion for Train 1, which reduced our associated guarantee by 60 percent. In August 2017, we reached financial completion for Train 2, which removed the remaining guarantee. See Note 11—Guarantees, for additional information.

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. See Note 2—Variable Interest Entities (VIEs) for additional information.

On July 1, 2016, APLNG changed its tax functional currency from Australian dollar to U.S. dollar and translated all APLNG assets and liabilities into U.S. dollar, utilizing the exchange rate as of that date. As a result of this change, we recorded a reduction to our investment in APLNG for the deferred tax effect of $174 million in the "Equity in earnings of affiliates" line of our consolidated income statement.

During the fourth quarter of 2015, due to the outlook for crude oil and natural gas prices at that time, the estimated fair value of our investment in APLNG declined to an amount below book value. Accordingly, we recorded a noncash $1,502 million before- and after-tax impairment, in our fourth-quarter 2015 results.

During the first and second quarters of 2017, the outlook for crude oil prices deteriorated, and as a result of significantly reduced price outlooks, the estimated fair value of our investment in APLNG declined to an amount below carrying value. Based on a review of the facts and circumstances surrounding this decline in fair value, we concluded in the second quarter of 2017 the impairment was other than temporary under the guidance of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 323, "Investments – Equity Method and Joint Ventures," and the recognition of an impairment of our investment to fair value was necessary. Accordingly, we recorded a noncash $2,384 million, before- and after-tax impairment in our second-quarter 2017 results. Fair value was estimated based on an internal discounted cash flow model using estimated future production, an outlook of future prices from a combination of exchanges (short-term) and pricing service companies (long-term), costs, a market outlook of foreign exchange rates provided by a third party, and a discount rate believed to be consistent with those used by principal market participants. The impairment was included in the "Impairments" line on our consolidated income statement.

At December 31, 2017, the carrying value of our equity method investment in APLNG was $7,669 million. The historical cost basis of our 37.5 percent share of net assets on the books of APLNG was $7,213 million, resulting in a basis difference of $456 million on our books. The basis difference, which is substantially all associated with PP&E and subject to amortization, has been allocated on a relative fair value basis to individual exploration and production license areas owned by APLNG, some of which are not currently in production. Any future additional payments are expected to be allocated in a similar manner. Each exploration license area will periodically be reviewed for any indicators of potential impairment, which, if required, would result in acceleration of basis difference amortization. As the joint venture produces natural gas from each license, we amortize the basis difference allocated to that license using the unit-of-production method. Included in net loss attributable to ConocoPhillips for 2017, 2016 and 2015 was after-tax expense of $100 million, $92 million and $21 million, respectively, representing the amortization of this basis difference on currently producing licenses.

**FCCL**
FCCL Partnership, a Canadian upstream 50/50 general partnership with Cenovus Energy Inc., produces bitumen in the Athabasca oil sands in northeastern Alberta and sells the bitumen blend. Cenovus is the operator and managing partner of FCCL.

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Financial information presented within this footnote includes our historical interest up to the date of sale. For additional information on the Canada disposition and our investment in Cenovus Energy, see Note 4—Assets Held for Sale, Sold or Acquired and Note 6—Investment in Cenovus Energy.

**QG3**
QG3 is a joint venture that owns an integrated large-scale LNG project located in Qatar. We provided project financing, with a current outstanding balance of $581 million as described below under "Loans and Long-Term Receivables." At December 31, 2017, the book value of our equity method investment in QG3, excluding the project financing, was $886 million. We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliated Golden Pass Pipeline near Sabine Pass, Texas, in which we have a 12.4 percent interest, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from QG3. However, currently the LNG from QG3 is being sold to markets outside of the United States.

**Loans and Long-Term Receivables**
As part of our normal ongoing business operations and consistent with industry practice, we enter into numerous agreements with other parties to pursue business opportunities. Included in such activity are loans and long-term receivables to certain affiliated and non-affiliated companies. Loans are recorded when cash is transferred or seller financing is provided to the affiliated or non-affiliated company pursuant to a loan agreement. The loan balance will increase as interest is earned on the outstanding loan balance and will decrease as interest and principal payments are received. Interest is earned at the loan agreement's stated interest rate. Loans and long-term receivables are assessed for impairment when events indicate the loan balance may not be fully recovered.

At December 31, 2017, significant loans to affiliated companies include $581 million in project financing to QG3. We own a 30 percent interest in QG3, for which we use the equity method of accounting. The other participants in the project are affiliates of Qatar Petroleum and Mitsui. QG3 secured project financing of $4.0 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. On December 15, 2011, QG3 achieved financial completion and all project loan facilities became nonrecourse to the project participants. Semi-annual repayments began in January 2011 and will extend through July 2022.

The long-term portion of these loans is included in the "Loans and advances—related parties" line on our consolidated balance sheet, while the short-term portion is in "Accounts and notes receivable—related parties."

**Note 6—Investment in Cenovus Energy**

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction included 208 million Cenovus Energy common shares, which approximated 16.9 percent of issued and outstanding Cenovus common shares at closing. See Note 4—Assets Held for Sale, Sold or Acquired, for additional information on the Canada disposition.

At closing, the fair value and cost basis of our investment in 208 million Cenovus Energy common shares was $1.96 billion based on a price of $9.41 per share on the New York Stock Exchange.

We have classified our investment as an available-for-sale equity security on our consolidated balance sheet and, as of December 31, 2017, our investment is carried at fair value of $1.90 billion, reflecting the closing price of Cenovus Energy shares on the New York Stock Exchange of $9.13 per share. The carrying value reflects a before-tax and after-tax unrealized loss of $58 million over our cost basis of $1.96 billion. The unrealized loss is reported as a component of accumulated other comprehensive loss. See Note 14—Fair Value Measurement, for additional information. We intend to decrease our investment over time through market transactions, private agreements or otherwise.

**Note 7—Suspended Wells and Other Exploration Expenses**

The following table reflects the net changes in suspended exploratory well costs during 2017, 2016 and 2015:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2017** | 2016 | 2015 |
| Beginning balance at January 1 | **$ 1,063** | 1,260 | 1,299 |
| Additions pending the determination of proved reserves | **118** | 225 | 331 |
| Reclassifications to proved properties | **(66)** | (27) | (28) |
| Sales of suspended well investment | **-** | (247) | - |
| Charged to dry hole expense | **(262)** | (148) | (342) |
| Ending balance at December 31 | **$ 853** | 1,063 | 1,260 |

The following table provides an aging of suspended well balances at December 31:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2017** | 2016 | 2015 |
| Exploratory well costs capitalized for a period of one year or less | **$ 67** | 132 | 235 |
| Exploratory well costs capitalized for a period greater than one year | **786** | 931 | 1,025 |
| Ending balance | **$ 853** | 1,063 | 1,260 |
| Number of projects with exploratory well costs capitalized for a period greater than one year | **23** | 26 | 28 |

The following table provides a further aging of those exploratory well costs that have been capitalized for more than one year since the completion of drilling as of December 31, 2017:

| | | Millions of Dollars | | | |
|---|---|---|---|---|---|
| | | | Suspended Since | | |
| | | Total | 2014–2016 | 2011–2013 | 2004–2010 |
| Greater Poseidon—Australia(2) | | 177 | 63 | 102 | 12 |
| Greater Clair—UK(2) | | 144 | 99 | 45 | - |
| Surmont—Canada(1) | | 117 | 34 | 59 | 24 |
| NPRA—Alaska(1) | | 114 | 66 | 42 | 6 |
| Barossa/Caldita—Australia(2) | | 77 | - | - | 77 |
| Middle Magdalena Basin—Colombia(1) | | 48 | 48 | - | - |
| Bohai—China(2) | | 19 | 19 | - | - |
| Kamunsu East—Malaysia(2) | | 19 | - | 19 | - |
| NC 98—Libya(2) | | 15 | 11 | - | 4 |
| Sunrise—Australia(2) | | 13 | - | - | 13 |
| Other of $10 million or less each(1)(2) | | 43 | 20 | 6 | 17 |
| Total | $ | 786 | 360 | 273 | 153 |

*(1)Additional appraisal wells planned.*
*(2)Appraisal drilling complete; costs being incurred to assess development.*

In line with our July 2015 announcement of plans to reduce future deepwater exploration spending, we recognized before-tax cancellation costs of $335 million and wrote off $48 million of before-tax capitalized rig costs in relation to the termination of our Gulf of Mexico deepwater drillship contract with Ensco in the Lower 48 segment in 2015. In July 2016, we entered into an agreement to terminate our final Gulf of Mexico deepwater drillship contract. The drillship, used to drill our operated deepwater well inventory in the Gulf of Mexico through April 2016, was contracted on a shared, three-year term. Accordingly, we recorded before-tax rig cancellation charges and third-party costs of $146 million in our Lower 48 segment in 2016.

In February 2017, we reached a settlement agreement on our contract for the Athena drilling rig, initially secured for our four-well commitment program in Angola. As a result of the cancellation, we recognized a before-tax charge of $43 million net in the first quarter of 2017. These charges are included in the “Exploration expenses” line on our consolidated income statement.

**Note 8—Impairments**

During 2017, 2016 and 2015, we recognized the following before-tax impairment charges:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| Alaska | **$** | **180** | 1 | 10 |
| Lower 48 | | **3,969** | 149 | (2) |
| Canada | | **22** | 88 | 4 |
| Europe and North Africa | | **46** | (160) | 724 |
| Asia Pacific and Middle East | | **2,384** | 44 | 1,508 |
| Corporate | | **-** | 17 | 1 |
| | **$** | **6,601** | 139 | 2,245 |

*2017*
In Alaska, we recorded impairments of $180 million primarily for the associated PP&E carrying value of our small interest in the Point Thomson unit.

In the Lower 48, we recorded impairments of $3,969 million primarily due to certain developed properties which were written down to fair value less costs to sell. See Note 4—Assets Held for Sale, Sold or Acquired, for additional information on our dispositions.

In Canada, we recorded impairments of $22 million primarily due to cancelled projects.

In Europe and North Africa, we recorded impairments of $46 million primarily due to reduced volume forecasts for a field in the United Kingdom and restructured ownership and a change in commercial premises for a gas processing plant in Norway, partly offset by decreased ARO estimates on fields at or nearing the end of life which were impaired in prior years.

In Asia Pacific and Middle East, we recorded impairments of $2,384 million, including the impairment of our APLNG investment. For more information, see the "APLNG" section of Note 5—Investments, Loans and Long-Term Receivables.

The charges discussed below, within this section, are included in the "Exploration expenses" line on our consolidated income statement and are not reflected in the table above.

In our Lower 48 segment, we recorded a before-tax impairment of $51 million for the associated carrying value of capitalized undeveloped leasehold costs of Shenandoah in deepwater Gulf of Mexico following the suspension of appraisal activity by the operator. Additionally, we recorded a $38 million before-tax impairment for mineral assets primarily due to plan of development changes.

*2016*
In the Lower 48, we recorded impairments of $149 million primarily due to cancelled projects associated with plan of development changes for Eagle Ford infrastructure, as well as lower natural gas prices and increased ARO estimates.

In Canada, we recorded impairments of $88 million mainly due to plan of development changes, as well as certain developed properties being written down to fair value less costs to sell.

In Europe and North Africa, we recorded a credit to impairment of $160 million, primarily in the United Kingdom, due to decreased ARO estimates on fields at or nearing the end of life which were impaired in prior years, partly offset by asset impairments due to lower natural gas prices in the United Kingdom.

In Asia Pacific and Middle East, we recorded impairments of $44 million, mainly due to a write-down to fair value less costs to sell of our developed properties in Block B, offshore Indonesia, in the third quarter of 2016.

In Corporate, we recorded impairments of $17 million due to cancelled projects in our Houston and Bartlesville offices.

The charges discussed below, within this section, are included in the "Exploration expenses" line on our consolidated income statement and are not reflected in the table above.

Charges recorded in exploration expenses in 2016 were related to our decision announced in 2015 to reduce deepwater exploration spending.

In our Lower 48 segment, we recorded a $203 million before-tax impairment for the associated carrying value of our Gibson and Tiber undeveloped leaseholds in deepwater Gulf of Mexico. Additionally, we recorded a $95 million before-tax impairment for the associated carrying value of capitalized undeveloped leasehold costs of the Melmar prospect and a $79 million before-tax impairment, primarily as a result of changes in the estimated market value following the completion of marketing efforts.

In our Canada segment, we recorded before-tax unproved property impairments of $31 million, primarily due to decisions to discontinue additional testing of undeveloped leaseholds.

*2015*

See the "APLNG" section of Note 5—Investments, Loans and Long-Term Receivables, for information on the impairment of our APLNG investment included within the Asia Pacific and Middle East segment.

In Europe and North Africa, we recorded impairments of $724 million, primarily in the United Kingdom as a result of lower natural gas prices and increases to AROs.

The charges discussed below, within this section, are included in the "Exploration expenses" line on our consolidated income statement and are not reflected in the table above.

In our Other International segment, we decided not to pursue further evaluation of our Block 36 and Block 37 leases in Angola due to lack of commerciality of wells. Accordingly, we recorded before-tax impairments of $377 million and $116 million, respectively, for the associated carrying values of capitalized undeveloped leasehold costs.

In our Lower 48 segment, we decided not to conduct further activity on certain Gulf of Mexico leases, given our strategic plans to reduce deepwater exploration spending, and accordingly recorded before-tax impairments of $399 million for the associated carrying value of certain capitalized undeveloped leasehold costs.

In our Asia Pacific and Middle East segment, we decided to relinquish our Palangkaraya PSC in Indonesia. Accordingly, we recorded a before-tax impairment of $105 million for the associated carrying values of capitalized undeveloped leasehold cost.

In our Alaska segment, we recorded a before-tax impairment of $575 million for the associated carrying value of capitalized undeveloped leasehold cost in the Chukchi Sea in Alaska.

In our Canada segment, we recorded a before-tax impairment of $102 million for the Duvernay, Thornbury, Saleski and Crow Lake areas driven primarily by the lack of commerciality of wells.

## Note 9—Asset Retirement Obligations and Accrued Environmental Costs

Asset retirement obligations and accrued environmental costs at December 31 were:

| | Millions of Dollars | |
|---|---|---|
| | **2017** | 2016 |
| Asset retirement obligations | **$ 7,798** | 8,405 |
| Accrued environmental costs | **180** | 247 |
| Total asset retirement obligations and accrued environmental costs | **7,978** | 8,652 |
| Asset retirement obligations and accrued environmental costs due within one year* | **(347)** | (227) |
| Long-term asset retirement obligations and accrued environmental costs | **$ 7,631** | 8,425 |

**Classified as a current liability on the balance sheet under "Other accruals."*

**Asset Retirement Obligations**
We record the fair value of a liability for an ARO when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize the associated asset retirement cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time, the liability increases for the change in its present value, while the capitalized cost depreciates over the useful life of the related asset.

We have numerous AROs we are required to perform under law or contract once an asset is permanently taken out of service. Most of these obligations are not expected to be paid until several years, or decades, in the future and will be funded from general company resources at the time of removal. Our largest individual obligations involve plugging and abandonment of wells and removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska.

During 2017 and 2016, our overall ARO changed as follows:

| | Millions of Dollars | |
|---|---|---|
| | **2017** | 2016 |
| Balance at January 1 | $ **8,405** | 9,911 |
| Accretion of discount | **358** | 420 |
| New obligations | **113** | 180 |
| Changes in estimates of existing obligations | **(150)** | (1,197) |
| Spending on existing obligations | **(152)** | (314) |
| Property dispositions | **(1,065)** | (150) |
| Foreign currency translation | **289** | (445) |
| Balance at December 31 | $ **7,798** | 8,405 |

**Accrued Environmental Costs**
Total accrued environmental costs at December 31, 2017 and 2016, were $180 million and $247 million, respectively.

We had accrued environmental costs of $105 million and $183 million at December 31, 2017 and 2016, respectively, related to remediation activities in the United States and Canada. We had also accrued in Corporate and Other $60 million and $51 million of environmental costs associated with sites no longer in operation at December 31, 2017 and 2016, respectively. In addition, $15 million and $13 million were included at both December 31, 2017 and 2016, respectively, where the company has been named a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act, or similar state laws. Accrued environmental liabilities are expected to be paid over periods extending up to 30 years.

Expected expenditures for environmental obligations acquired in various business combinations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $96 million at December 31, 2017. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $12 million in 2018, $10 million in 2019, $5 million in 2020, $10 million in 2021, $3 million in 2022, and $106 million for all future years after 2022.

### Note 10—Debt

Long-term debt at December 31 was:

| | Millions of Dollars | |
|---|---|---|
| | **2017** | 2016 |
| 9.125% Debentures due 2021 | $ **150** | 150 |
| 8.20% Debentures due 2025 | **150** | 150 |
| 8.125% Notes due 2030 | **600** | 600 |
| 7.9% Debentures due 2047 | **100** | 100 |
| 7.8% Debentures due 2027 | **300** | 300 |
| 7.65% Debentures due 2023 | **88** | 88 |
| 7.40% Notes due 2031 | **500** | 500 |
| 7.375% Debentures due 2029 | **92** | 92 |
| 7.25% Notes due 2031 | **500** | 500 |
| 7.20% Notes due 2031 | **575** | 575 |
| 7% Debentures due 2029 | **200** | 200 |
| 6.95% Notes due 2029 | **1,549** | 1,549 |
| 6.875% Debentures due 2026 | **67** | 67 |
| 6.65% Debentures due 2018 | **-** | 297 |
| 6.50% Notes due 2039 | **2,750** | 2,750 |
| 6.00% Notes due 2020 | **-** | 1,000 |
| 5.951% Notes due 2037 | **645** | 645 |
| 5.95% Notes due 2036 | **500** | 500 |
| 5.95% Notes due 2046 | **500** | 500 |
| 5.90% Notes due 2032 | **505** | 505 |
| 5.90% Notes due 2038 | **600** | 600 |
| 5.75% Notes due 2019 | **-** | 2,250 |
| 5.20% Notes due 2018 | **-** | 500 |
| 4.95% Notes due 2026 | **1,250** | 1,250 |
| 4.30% Notes due 2044 | **750** | 750 |
| 4.20% Notes due 2021 | **1,000** | 1,250 |
| 4.15% Notes due 2034 | **500** | 500 |
| 3.35% Notes due 2024 | **1,000** | 1,000 |
| 3.35% Notes due 2025 | **500** | 500 |
| 2.875% Notes due 2021 | **750** | 750 |
| 2.4% Notes due 2022 | **1,000** | 1,000 |
| 2.2% Notes due 2020 | **500** | 500 |
| 1.5% Notes due 2018 | **-** | 750 |
| 1.05% Notes due 2017 | **-** | 1,000 |
| Floating rate term loan due 2019 at 2.31% – 2.75% during 2017 and 1.94% – 2.31% during 2016 | **-** | 1,450 |
| Floating rate notes due 2018 at 1.24% – 1.75% during 2017 and 0.69% – 1.24% during 2016 | **250** | 250 |
| Floating rate notes due 2022 at 1.81% – 2.32% during 2017 and 1.26% – 1.81% during 2016 | **500** | 500 |
| Industrial Development Bonds due 2017 through 2038 at 0.64% – 1.74% during 2017 and 0.01% – 0.91% during 2016 | **18** | 18 |
| Marine Terminal Revenue Refunding Bonds due 2031 at 0.64% – 1.74% during 2017 and 0.01% – 0.95% during 2016 | **265** | 265 |
| Other | **23** | 24 |
| Debt at face value | **18,677** | 26,175 |
| Capitalized leases | **774** | 852 |
| Net unamortized premiums, discounts and debt issuance costs | **252** | 248 |
| Total debt | **19,703** | 27,275 |
| Short-term debt | **(2,575)** | (1,089) |
| Long-term debt | $ **17,128** | 26,186 |

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2018 through 2022 are: $2,575 million, $113 million, $97 million, $236 million and $1,602 million, respectively.

We have a revolving credit facility totaling $6.75 billion, expiring in June 2019. Our revolving credit facility may be used for direct bank borrowings, the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper programs. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the United States. The agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

We have two commercial paper programs. The ConocoPhillips $6.25 billion commercial paper program is available to fund short-term working capital needs. We also have the ConocoPhillips Qatar Funding Ltd. $500 million commercial paper program, which is used to fund commitments relating to QG3. Commercial paper maturities are generally limited to 90 days. We had no commercial paper outstanding at December 31, 2017 or 2016, under either the ConocoPhillips or the ConocoPhillips Qatar Funding Ltd. commercial paper program. We had no direct borrowings or letters of credit issued under the revolving credit facility. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.75 billion in borrowing capacity under our revolving credit facility at December 31, 2017.

In 2017, two notes totaling $1,001 million were paid at maturity, including the $1.0 billion 1.05% Notes due 2017. Also in 2017, we prepaid the $1,450 million term loan facility due in 2019.

We also redeemed a total $5.0 billion of debt, described below, incurring $301 million in premiums above book value, which are reported in the "Other expense" line on our consolidated income statement.

- 6.65% Debentures due 2018 with principal of $297 million.
- 5.20% Notes due 2018 with principal of $500 million.
- 1.5% Notes due 2018 with principal of $750 million.
- 5.75% Notes due 2019 with principal of $2.25 billion.
- 6.00% Notes due 2020 with principal of $1.0 billion.
- 4.20% Notes due 2021 with principal of $1.25 billion (partial redemption of $250 million).

In the fourth quarter of 2017, we gave notice to redeem the following debt instruments totaling $2.25 billion.

- 2.2% Notes due 2020 with principal of $500 million.
- 4.20% Notes due 2021 with remaining principal of $1.0 billion.
- 2.875% Notes due 2021 with principal of $750 million.

The prepayments occurred on January 22, 2018, and we incurred premiums above book value of $75 million.

At both December 31, 2017 and 2016, we had $283 million of certain variable rate demand bonds (VRDBs) outstanding with maturities ranging through 2035. The VRDBs are redeemable at the option of the bondholders on any business day. The VRDBs are included in the "Long-term debt" line on our consolidated balance sheet.

During 2013, a lease of a semi-submersible floating production system (FPS) commenced for the Gumusut development, located in Malaysia, in which we are a co-venturer. The FPS lease provides for an initial noncancelable term of 15 years, a subsequent 5-year cancelable term with no required lease payments, and an additional 5-year term with terms and conditions to be agreed at a later date. The lease has no ongoing purchase options or escalation clauses. Adjustments to provisional contingent rental payments may occur due to the finalization of actual commissioning costs. The lease does not impose any significant restrictions concerning dividends, debt or further leasing activities.

A capital lease asset and capital lease obligation were recognized for our proportionate interest in the FPS of $906 million, based on the present value of the future minimum lease payments using our before-tax incremental borrowing rate of 3.58 percent for debt with similar terms. Our proportionate interest in the FPS is 29 percent as of December 31, 2017. The net carrying value of the capital lease asset was approximately $434 million and $540 million as of December 31, 2017 and 2016, respectively. The capital lease asset is being depreciated over a period consistent with the estimated proved reserves of Gumusut using the unit-of-production method with the associated depreciation included in the "Depreciation, depletion and amortization" line on our consolidated income statement. As of December 31, 2017 and 2016, accumulated depreciation of the capital lease asset amounted to approximately $381 million and $268 million, respectively.

At December 31, 2017, future minimum payments due under capital leases were:

| | Millions of Dollars |
|---|---|
| 2018 | $ 108 |
| 2019 | 106 |
| 2020 | 106 |
| 2021 | 88 |
| 2022 | 88 |
| Remaining years | 487 |
| Total | 983 |
| Less: portion representing imputed interest | (209) |
| Capital lease obligations | $ 774 |

**Note 11—Guarantees**

At December 31, 2017, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability, at inception, for the fair value of our obligation as a guarantor for newly issued or modified guarantees. Unless the carrying amount of the liability is noted below, we have not recognized a liability because the fair value of the obligation is immaterial. In addition, unless otherwise stated, we are not currently performing with any significance under the guarantee and expect future performance to be either immaterial or have only a remote chance of occurrence.

**APLNG Guarantees**

At December 31, 2017, we had outstanding multiple guarantees in connection with our 37.5 percent ownership interest in APLNG. The following is a description of the guarantees with values calculated utilizing December 2017 exchange rates:

- We guaranteed APLNG's performance with regard to a construction contract executed in connection with APLNG's issuance of the Train 1 and Train 2 Notices to Proceed. Our maximum potential amount of future payments related to this guarantee became immaterial in the second quarter of 2017.

- We issued a construction completion guarantee related to the third-party project financing secured by APLNG. In October 2016, we reached financial completion for Train 1, releasing a portion of our guarantee. In August 2017, the two-train project finance lenders' test was completed, releasing the remaining guarantee.

- During the third quarter of 2016, we issued a guarantee to facilitate the withdrawal of our pro-rata portion of the funds in a project finance reserve account. We estimate the remaining term of this guarantee is 12 years. Our maximum exposure under this guarantee is approximately $200 million and may become payable if an enforcement action is commenced by the project finance lenders against APLNG. At December 31, 2017, the carrying value of this guarantee is approximately $14 million.

- In conjunction with our original purchase of an ownership interest in APLNG from Origin Energy in October 2008, we agreed to reimburse Origin Energy for our share of the existing contingent liability arising under guarantees of an existing obligation of APLNG to deliver natural gas under several sales agreements with remaining terms of up to 24 years. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $960 million ($1.71 billion in the event of intentional or reckless breach) and would become payable if APLNG fails to meet its obligations under these agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, would only be triggered if APLNG does not have enough natural gas to meet these sales commitments and if the co-venturers do not make necessary equity contributions into APLNG.

- We have guaranteed the performance of APLNG with regard to certain other contracts executed in connection with the project's continued development. The guarantees have remaining terms of up to 28 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $150 million and would become payable if APLNG does not perform.

**Other Guarantees**

We have other guarantees with maximum future potential payment amounts totaling approximately $780 million, which consist primarily of guarantees of the residual value of leased office buildings, guarantees of the residual value of leased corporate aircraft, and a guarantee for our portion of a joint venture's project finance reserve accounts. These guarantees have remaining terms of up to 5 years and would become payable if, upon sale, certain asset values are lower than guaranteed amounts, business conditions decline at guaranteed entities, or as a result of nonperformance of contractual terms by guaranteed parties.

**Indemnifications**

Over the years, we have entered into agreements to sell ownership interests in certain corporations, joint ventures and assets that gave rise to qualifying indemnifications. These agreements include indemnifications for taxes, environmental liabilities, employee claims and litigation. The terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications at December 31, 2017, was approximately $100 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the recorded carrying amount at December 31, 2017, were approximately $40 million of environmental accruals for known contamination that are included in the "Asset retirement obligations and accrued environmental costs" line on our consolidated balance sheet. For additional information about environmental liabilities, see Note 12—Contingencies and Commitments.

In 2012, we completed the separation of our downstream business, creating two independent energy companies: ConocoPhillips and Phillips 66. On March 1, 2015, a supplier to one of the refineries included in Phillips 66 as part of the separation of our downstream business formally registered Phillips 66 as a party to the supply agreement, thereby triggering a guarantee we provided at the time of separation. Our maximum potential liability for future payments under this guarantee, which would become payable if Phillips 66 does not perform its contractual obligations under the supply agreement, is approximately $1.31 billion. At December 31, 2017, the carrying value of this guarantee is approximately $98 million and the remaining term is seven years. Because Phillips 66 has indemnified us for losses incurred under this guarantee, we have recorded an indemnification asset from Phillips 66 of approximately $98 million. The recorded indemnification asset amount represents the estimated fair value of the guarantee; however, if we are required to perform under the guarantee, we would expect to recover from Phillips 66 any amounts in excess of that value, provided Phillips 66 is a going concern.

## Note 12—Contingencies and Commitments

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. With respect to income tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. See Note 18—Income Taxes, for additional information about income tax-related contingencies.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

### Environmental

We are subject to international, federal, state and local environmental laws and regulations. When we prepare our consolidated financial statements, we record accruals for environmental liabilities based on management's best estimates, using all information that is available at the time. We measure estimates and base liabilities on currently available facts, existing technology, and presently enacted laws and regulations, taking into account stakeholder and business considerations. When measuring environmental liabilities, we also consider our prior experience in remediation of contaminated sites, other companies' cleanup experience, and data released by the U.S. Environmental Protection Agency (EPA) or other organizations. We consider unasserted claims in our determination of environmental liabilities, and we accrue them in the period they are both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for other sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all cleanup costs related to any site at which we have been designated as a potentially responsible party. We have been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the agency concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, we consider this inability in estimating our potential liability, and we adjust our accruals accordingly. As a result of various acquisitions in the past, we assumed certain environmental obligations. Some of these environmental obligations are mitigated by indemnifications made by others for our benefit, and some of the indemnifications are subject to dollar limits and time limits.

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state and international sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. See Note 9—Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

**Legal Proceedings**

We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, personal injury, and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required.

**Other Contingencies**

We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at December 31, 2017, we had performance obligations secured by letters of credit of $338 million (issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, commercial activities and services incident to the ordinary conduct of business.

In 2007, we announced we had been unable to reach agreement with respect to our migration to an *empresa mixta* structure mandated by the Venezuelan government's Nationalization Decree. As a result, Venezuela's national oil company, Petróleos de Venezuela S.A. (PDVSA), or its affiliates, directly assumed control over ConocoPhillips' interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, we filed a request for international arbitration on November 2, 2007, with the World Bank's International Centre for Settlement of Investment Disputes (ICSID). An arbitration hearing was held before an ICSID tribunal during the summer of 2010. On September 3, 2013, an ICSID arbitration tribunal held that Venezuela unlawfully expropriated ConocoPhillips' significant oil investments in June 2007. On January 17, 2017, the Tribunal reconfirmed the decision that the expropriation was unlawful. A separate arbitration phase is currently proceeding to determine the damages owed to ConocoPhillips for Venezuela's actions. Separate arbitrations for contractual compensation against PDVSA are also pending before an International Chamber of Commerce (ICC) arbitration tribunal. In addition, ConocoPhillips brought fraudulent transfer actions in the U.S. District Court of Delaware, alleging that PDVSA has taken actions to improperly expatriate assets from the United States to Venezuela in an effort to avoid judgment creditors.

In 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before ICSID against The Republic of Ecuador challenging a windfall profits tax and subsequent expropriation of Blocks 7 and 21. On April 24, 2012, Ecuador filed environmental and infrastructure counterclaims against Burlington relating to alleged impacts to Blocks 7 and 21. Ecuador also filed the environmental and infrastructure counterclaims relating to Blocks 7 and 21 in a separate, parallel ICSID arbitration brought by Perenco Ecuador Limited, Burlington's co-venturer and consortium operator. Perenco and Burlington each have joint liability for the counterclaims under their joint operating agreements. On December 14, 2012, the ICSID tribunal issued a decision in favor of Burlington, finding that Ecuador's seizure of Blocks 7 and 21 was an unlawful expropriation in violation of the Ecuador-U.S. Bilateral Investment Treaty. In February 2017, the ICSID tribunal unanimously awarded Burlington $380 million for Ecuador’s unlawful expropriation and breach of the U.S.-Ecuador bilateral investment treaty. The tribunal also issued a separate decision finding Ecuador to be entitled to $42 million for environmental and infrastructure impacts to Blocks 7 and 21. In December 2017, Burlington and Ecuador entered into a settlement agreement by which Ecuador agreed to pay Burlington $337 million in two installments. The first installment of $75 million was timely paid on December 1, 2017. The second installment of $262 million is to be paid by April 2018. The settlement includes an offset for the counterclaims decision, of which Burlington is entitled to a $24 million contribution from Perenco pursuant to the joint operating agreement. The ICSID arbitration between Perenco and Ecuador remains pending.

In December 2016, ConocoPhillips Angola filed a notice of arbitration against Sonangol E.P. under the Block 36 Production Sharing Contract relating to disputes arising thereunder. The arbitration is being conducted under the United Nations Commission on International Trade Laws (UNCITRAL) rules using a three-person tribunal.

In June 2017, FAR Ltd. initiated arbitration before the ICC against ConocoPhillips Senegal B.V. in connection with the sale of ConocoPhillips Senegal B.V. to Woodside Energy Holdings (Senegal) Limited in 2016. The arbitral tribunal is in the process of being constituted.

In 2017 and early 2018, cities and/or counties in California and New York have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. ConocoPhillips will be vigorously defending against these lawsuits.

**Long-Term Throughput Agreements and Take-or-Pay Agreements**

We have certain throughput agreements and take-or-pay agreements in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the company’s business. The aggregate amounts of estimated payments under these various agreements are: 2018—$21 million; 2019—$7 million; 2020—$7 million; 2021—$7 million; 2022—$7 million; and 2023 and after—$74 million. Total payments under the agreements were $43 million in 2017, $42 million in 2016 and $27 million in 2015.

## Note 13—Derivative and Financial Instruments

We use futures, forwards, swaps and options in various markets to meet our customer needs and capture market opportunities. Our commodity business primarily consists of natural gas, crude oil, bitumen, LNG and natural gas liquids.

Our derivative instruments are held at fair value on our consolidated balance sheet. Where these balances have the right of setoff, they are presented on a net basis. Related cash flows are recorded as operating activities on our consolidated statement of cash flows. On our consolidated income statement, realized and unrealized gains and losses are recognized either on a gross basis if directly related to our physical business or a net basis if held for trading. Gains and losses related to contracts that meet and are designated with the normal purchase normal sale exception are recognized upon settlement. We generally apply this exception to eligible crude contracts. We do not use hedge accounting for our commodity derivatives.

The following table presents the gross fair values of our commodity derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

| | Millions of Dollars | |
|---|---|---|
| | **2017** | 2016 |
| **Assets** | | |
| Prepaid expenses and other current assets | $ **275** | 268 |
| Other assets | **36** | 44 |
| **Liabilities** | | |
| Other accruals | **282** | 300 |
| Other liabilities and deferred credits | **28** | 34 |

The gains (losses) from commodity derivatives incurred, and the line items where they appear on our consolidated income statement were:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2017** | 2016 | 2015 |
| Sales and other operating revenues | $ **77** | (198) | 231 |
| Other income | **-** | (1) | 2 |
| Purchased commodities | **(61)** | 161 | (201) |

The table below summarizes our material net exposures resulting from outstanding commodity derivative contracts:

| | Open Position Long/(Short) | |
|---|---|---|
| | **2017** | 2016 |
| **Commodity** | | |
| Natural gas and power (billions of cubic feet equivalent) | | |
| Fixed price | **(29)** | (31) |
| Basis | **12** | 2 |

**Foreign Currency Exchange Derivatives**

We have foreign currency exchange rate risk resulting from international operations. Our foreign currency exchange derivative activity primarily relates to managing our cash-related foreign currency exchange rate exposures, such as firm commitments for capital programs or local currency tax payments, dividends and cash returns from net investments in foreign affiliates, and investments in available-for-sale securities. We do not elect hedge accounting on our foreign currency exchange derivatives.

The following table presents the gross fair values of our foreign currency exchange derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2017** | 2016 |
| **Assets** | | | |
| Prepaid expenses and other current assets | **$** | **1** | 1 |
| Other assets | | **6** | - |
| **Liabilities** | | | |
| Other accruals | | **-** | 168 |
| Other liabilities and deferred credits | | **15** | - |

In December 2017, we entered into foreign exchange zero cost collars buying the right to sell $1.25 billion CAD at $0.707 CAD and selling the right to buy $1.25 billion CAD at $0.842 CAD against the U.S. dollar.

The (gains) losses from foreign currency exchange derivatives incurred and the line item where they appear on our consolidated income statement were:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| Foreign currency transaction (gains) losses | **$** | **13** | 247 | (33) |

We had the following net notional position of outstanding foreign currency exchange derivatives:

| | | In Millions Notional Currency | |
|---|---|---|---|
| | | **2017** | 2016 |
| **Foreign Currency Exchange Derivatives** | | | |
| Sell U.S. dollar, buy other currencies(1) | USD | **-** | 13 |
| Buy U.S. dollar, sell other currencies(2) | USD | **-** | 25 |
| Buy British pound, sell other currencies(3) | GBP | **-** | 1,069 |
| Sell British pound, buy other currencies(4) | GBP | **1** | 51 |
| Sell Canadian dollar, buy U.S. dollar | CAD | **1,225** | - |

*(1)Primarily Canadian dollar.*
*(2)Primarily British pound.*
*(3)Primarily Canadian dollar.*
*(4)Primarily euro and Norwegian krone.*

**Financial Instruments**
We invest excess cash in financial instruments with maturities based on our cash forecasts for the various currency pools we manage. The maturities of these investments may from time to time extend beyond 90 days. The types of financial instruments that we currently invest include:

- Time deposits: Interest bearing deposits placed with approved financial institutions.
- Commercial paper: Unsecured promissory notes issued by a corporation, commercial bank or government agency purchased at a discount to mature at par.

These financial instruments appear in the “Cash and cash equivalents” line of our consolidated balance sheet if the maturities at the time we made the investments were 90 days or less; otherwise, these financial instruments are included in the “Short-term investments” line on our consolidated balance sheet.

| | | Millions of Dollars | | | |
|---|---|---|---|---|---|
| | | Carrying Amount | | | |
| | | Cash and Cash Equivalents | | Short-Term Investments | |
| | | **2017** | 2016 | **2017** | 2016 |
| **Cash** | $ | **948** | 623 | **-** | - |
| **Time deposits** | | | | | |
| Remaining maturities from 1 to 90 days | | **5,004** | 2,987 | **821** | 39 |
| Remaining maturities from 91 to 180 days | | **-** | - | **-** | 11 |
| **Commercial paper** | | | | | |
| Remaining maturities from 1 to 90 days | | **373** | - | **978** | - |
| Remaining maturities from 91 to 180 days | | **-** | - | **74** | - |
| | $ | **6,325** | 3,610 | **1,873** | 50 |

**Credit Risk**

Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalents, short-term investments, over-the-counter (OTC) derivative contracts and trade receivables. Our cash equivalents and short-term investments are placed in high-quality commercial paper, government money market funds, government debt securities and time deposits with major international banks and financial institutions.

The credit risk from our OTC derivative contracts, such as forwards, swaps and options, derives from the counterparty to the transaction. Individual counterparty exposure is managed within predetermined credit limits and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant nonperformance. We also use futures, swaps and option contracts that have a negligible credit risk because these trades are cleared with an exchange clearinghouse and subject to mandatory margin requirements until settled; however, we are exposed to the credit risk of those exchange brokers for receivables arising from daily margin cash calls, as well as for cash deposited to meet initial margin requirements.

Our trade receivables result primarily from our petroleum operations and reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less, and we continually monitor this exposure and the creditworthiness of the counterparties. We do not generally require collateral to limit the exposure to loss; however, we will sometimes use letters of credit, prepayments and master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to us, as these agreements permit the amounts owed by us or owed to others to be offset against amounts due to us.

Certain of our derivative instruments contain provisions that require us to post collateral if the derivative exposure exceeds a threshold amount. We have contracts with fixed threshold amounts and other contracts with variable threshold amounts that are contingent on our credit rating. The variable threshold amounts typically decline for lower credit ratings, while both the variable and fixed threshold amounts typically revert to zero if we fall below investment grade. Cash is the primary collateral in all contracts; however, many also permit us to post letters of credit as collateral, such as transactions administered through the New York Mercantile Exchange.

The aggregate fair value of all derivative instruments with such credit risk-related contingent features that were in a liability position on December 31, 2017 and December 31, 2016, was $55 million and $42 million, respectively. For these instruments, no collateral was posted as of December 31, 2017, or December 31, 2016. If our credit rating had been downgraded below investment grade on December 31, 2017, we would be required to post $55 million of additional collateral, either with cash or letters of credit.

**Note 14—Fair Value Measurement**

We carry a portion of our assets and liabilities at fair value that are measured at a reporting date using an exit price (i.e., the price that would be received to sell an asset or paid to transfer a liability) and disclosed according to the quality of valuation inputs under the following hierarchy:

- Level 1: Quoted prices (unadjusted) in an active market for identical assets or liabilities.
- Level 2: Inputs other than quoted prices that are directly or indirectly observable.
- Level 3: Unobservable inputs that are significant to the fair value of assets or liabilities.

The classification of an asset or liability is based on the lowest level of input significant to its fair value. Those that are initially classified as Level 3 are subsequently reported as Level 2 when the fair value derived from unobservable inputs is inconsequential to the overall fair value, or if corroborated market data becomes available. Assets and liabilities initially reported as Level 2 are subsequently reported as Level 3 if corroborated market data is no longer available. Transfers occur at the end of the reporting period. At the end of the fourth quarter of 2017, our $1,899 million investment in Cenovus Energy was transferred from Level 2 to Level 1 due to the lapsing of trading restrictions. There were no other material transfers in or out of Level 1 during 2017 or 2016.

**Recurring Fair Value Measurement**

Financial assets and liabilities reported at fair value on a recurring basis primarily include commodity derivatives. Level 1 derivative assets and liabilities primarily represent exchange-traded futures and options that are valued using unadjusted prices available from the underlying exchange. This also includes our investment in common shares of Cenovus Energy, which is valued using quotes for shares on the New York Stock Exchange. Level 2 derivative assets and liabilities primarily represent OTC swaps, options and forward purchase and sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data. Level 3 derivative assets and liabilities consist of OTC swaps, options and forward purchase and sale contracts where a significant portion of fair value is calculated from underlying market data that is not readily available. The derived value uses industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management's best estimate of fair value. Level 3 activity was not material for all periods presented.

The following table summarizes the fair value hierarchy for gross financial assets and liabilities (i.e., unadjusted where the right of setoff exists for commodity derivatives accounted for at fair value on a recurring basis):

| | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **December 31, 2017** | | | | December 31, 2016 | | | |
| | **Level 1** | **Level 2** | **Level 3** | **Total** | Level 1 | Level 2 | Level 3 | Total |
| **Assets** | | | | | | | | |
| Investment in Cenovus Energy | **$ 1,899** | **-** | **-** | **1,899** | - | - | - | - |
| Commodity derivatives | **175** | **106** | **30** | **311** | 194 | 96 | 22 | 312 |
| Total assets | **$ 2,074** | **106** | **30** | **2,210** | 194 | 96 | 22 | 312 |
| **Liabilities** | | | | | | | | |
| Commodity derivatives | **$ 158** | **111** | **41** | **310** | 207 | 105 | 22 | 334 |
| Total liabilities | **$ 158** | **111** | **41** | **310** | 207 | 105 | 22 | 334 |

The following table summarizes those commodity derivative balances subject to the right of setoff as presented on our consolidated balance sheet. We have elected to offset the recognized fair value amounts for multiple derivative instruments executed with the same counterparty in our financial statements when a legal right of offset exists.

| | | Millions of Dollars | | | | |
|---|---|---|---|---|---|---|
| | | Gross Amounts Recognized | Gross Amounts Offset | Net Amounts Presented | Cash Collateral | Gross Amounts without Right of Setoff | Net Amounts |
| **December 31, 2017** | | | | | | | |
| Assets | **$** | **311** | **186** | **125** | **-** | **4** | **121** |
| Liabilities | | **310** | **186** | **124** | **7** | **5** | **112** |
| December 31, 2016 | | | | | | | |
| Assets | $ | 312 | 221 | 91 | - | 5 | 86 |
| Liabilities | | 334 | 221 | 113 | 12 | 12 | 89 |

At December 31, 2017, and December 31, 2016, we did not present any amounts gross on our consolidated balance sheet where we had the right of setoff.

**Non-Recurring Fair Value Measurement**

The following table summarizes the fair value hierarchy by major category and date of remeasurement for assets accounted for at fair value on a non-recurring basis:

| | | Millions of Dollars | | | |
|---|---|---|---|---|---|
| | | | Fair Value Measurements Using | | |
| | | Fair Value | Level 1 Inputs | Level 3 Inputs | Before-Tax Loss |
| **Year ended December 31, 2017** | | | | | |
| Net PP&E (held for use) | | | | | |
| December 31, 2017 | **$** | **75** | **-** | **75** | **154** |
| Net PP&E (held for sale) | | | | | |
| June 30, 2017 | | **2,830** | **2,830** | **-** | **3,882** |
| December 31, 2017 | | **113** | **113** | **-** | **78** |
| Cost and equity method investments | | | | | |
| June 30, 2017 | | **7,656** | **-** | **7,656** | **2,384** |
| Year ended December 31, 2016 | | | | | |
| Net PP&E (held for use) | | | | | |
| March 31, 2016 | $ | 217 | - | 217 | 129 |
| June 30, 2016 | | 23 | - | 23 | 53 |
| December 31, 2016 | | 13 | - | 13 | 29 |
| Net PP&E (held for sale) | | | | | |
| September 30, 2016 | | 217 | 217 | - | 99 |
| Cost and equity method investments | | | | | |
| December 31, 2016 | | 90 | 4 | 86 | 40 |

*Net PP&E (held for use)*

Net PP&E held for use is comprised of various producing properties impaired to their individual fair values less costs to sell. The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges and pricing service companies, costs, and a discount rate believed to be consistent with those used by principal market participants.

*Net PP&E (held for sale)*
Net PP&E held for sale was written down to fair value, less costs to sell. The fair value of each asset was determined by its negotiated selling price.

*Equity Method Investments*
Certain cost and equity method investments were determined to have fair values below their carrying amounts, and the impairments were considered to be other than temporary under the guidance of FASB ASC Topic 323. During 2017, this included our investment in APLNG, which was written down to its fair value of $7,656 million, resulting in a before-tax-charge of $2,384 million. For additional information on APLNG, see Note 5—Investments, Loans and Long-Term Receivables. During 2016, an investment using Level 1 inputs was written down to fair value, less costs to sell, determined by its negotiated selling price. Investments using Level 3 inputs had fair values determined primarily by internal discounted cash flow models using estimates of future production, prices from futures exchanges and pricing service companies, costs, and a discount factor believed to be consistent with those used by principal market participants.

**Reported Fair Values of Financial Instruments**
We used the following methods and assumptions to estimate the fair value of financial instruments:

- Cash and cash equivalents and short-term investments: The carrying amount reported on the balance sheet approximates fair value.
- Accounts and notes receivable (including long-term and related parties): The carrying amount reported on the balance sheet approximates fair value. The valuation technique and methods used to estimate the fair value of the current portion of fixed-rate related party loans is consistent with Loans and advances—related parties.
- Investment in Cenovus Energy shares: See Note 6—Investment in Cenovus Energy for a discussion of the carrying value and fair value of our investment in Cenovus Energy shares.
- Loans and advances—related parties: The carrying amount of floating-rate loans approximates fair value. The fair value of fixed-rate loan activity is measured using market observable data and is categorized as Level 2 in the fair value hierarchy. See Note 5—Investments, Loans and Long-Term Receivables, for additional information.
- Accounts payable (including related parties) and floating-rate debt: The carrying amount of accounts payable and floating-rate debt reported on the balance sheet approximates fair value.
- Fixed-rate debt: The estimated fair value of fixed-rate debt is measured using prices available from a pricing service that is corroborated by market data; therefore, these liabilities are categorized as Level 2 in the fair value hierarchy.

The following table summarizes the net fair value of financial instruments (i.e., adjusted where the right of setoff exists for commodity derivatives):

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | Carrying Amount | | Fair Value | |
| | **2017** | 2016 | **2017** | 2016 |
| **Financial assets** | | | | |
| Investment in Cenovus Energy | $ **1,899** | - | **1,899** | - |
| Commodity derivatives | **125** | 91 | **125** | 91 |
| Total loans and advances—related parties | **586** | 701 | **586** | 701 |
| **Financial liabilities** | | | | |
| Total debt, excluding capital leases | **18,929** | 26,423 | **22,435** | 29,307 |
| Commodity derivatives | **117** | 101 | **117** | 101 |

*Commodity Derivatives*
At December 31, 2017, commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $7 million of rights to reclaim cash collateral, respectively. At December 31, 2016,

commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $12 million of rights to reclaim cash collateral, respectively.

## Note 15—Equity

### Common Stock

The changes in our shares of common stock, as categorized in the equity section of the balance sheet, were:

| | Shares | | |
|---|---|---|---|
| | **2017** | 2016 | 2015 |
| **Issued** | | | |
| Beginning of year | **1,782,079,107** | 1,778,226,388 | 1,773,583,368 |
| Distributed under benefit plans | **3,340,068** | 3,852,719 | 4,643,020 |
| End of year | **1,785,419,175** | 1,782,079,107 | 1,778,226,388 |
| **Held in Treasury** | | | |
| Beginning of year | **544,809,771** | 542,230,673 | 542,230,673 |
| Repurchase of common stock | **63,502,263** | 2,579,098 | - |
| End of year | **608,312,034** | 544,809,771 | 542,230,673 |

### Preferred Stock

We have authorized 500 million shares of preferred stock, par value $.01 per share, none of which was issued or outstanding at December 31, 2017 or 2016.

### Noncontrolling Interests

At December 31, 2017 and 2016, we had $194 million and $252 million outstanding, respectively, of equity in less-than-wholly owned consolidated subsidiaries held by noncontrolling interest owners. For both periods, the amounts were related to the Darwin LNG and Bayu-Darwin Pipeline operating joint ventures we control.

### Repurchase of Common Stock

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock through 2019. On March 29, 2017, we announced plans to double our share repurchase program to $6 billion of common stock through 2019, with $3 billion allocated and purchased in 2017, and the remainder allocated evenly to 2018 and 2019. On February 1, 2018, we announced the acceleration of our previously stated 2018 share repurchases from $1.5 billion to $2.0 billion, with the remaining balance to be repurchased in 2019. Repurchase of shares began in November 2016, and totaled 66,081,361 shares at a cost of $3,126 million, through December 31, 2017.

### Note 16—Non-Mineral Leases

The company primarily leases drilling equipment and office buildings, as well as ocean transport vessels, tugboats, barges, corporate aircraft, computers and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices, as well as renewal options and/or options to purchase the leased property for the fair market value at the end of the lease term. There are no significant restrictions imposed on us by the leasing agreements with regard to dividends, asset dispositions or borrowing ability. For additional information on leased assets under capital leases, see Note 10—Debt.

At December 31, 2017, future minimum rental payments due under noncancelable leases were:

| | Millions of Dollars |
|---|---|
| 2018 | $ 278 |
| 2019 | 214 |
| 2020 | 414 |
| 2021 | 126 |
| 2022 | 307 |
| Remaining years | 209 |
| Total | 1,548 |
| Less: income from subleases | (11) |
| Net minimum operating lease payments | $ 1,537 |

Operating lease rental expense for the years ended December 31 was:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2017** | 2016 | 2015 |
| Total rentals | **$ 264** | 537 | 432 |
| Less: sublease rentals | **(20)** | (10)* | (9) |
| | **$ 244** | 527 | 423 |

**Amount updated to reflect additional sublease income in 2016.*

## Note 17—Employee Benefit Plans

### Pension and Postretirement Plans

An analysis of the projected benefit obligations for our pension plans and accumulated benefit obligations for our postretirement health and life insurance plans follows:

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Pension Benefits | | | | Other Benefits | |
| | **2017** | | 2016 | | **2017** | 2016 |
| | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| **Change in Benefit Obligation** | | | | | | |
| Benefit obligation at January 1 | **$ 3,416** | **3,445** | 3,772 | 3,321 | **286** | 352 |
| Service cost | **89** | **77** | 108 | 76 | **2** | 2 |
| Interest cost | **118** | **103** | 133 | 120 | **9** | 13 |
| Plan participant contributions | **-** | **2** | - | 3 | **23** | 24 |
| Plan amendments | **-** | **-** | - | - | **-** | (27) |
| Actuarial (gain) loss | **244** | **52** | 247 | 466 | **12** | (14) |
| Benefits paid | **(631)** | **(117)** | (872) | (148) | **(68)** | (68) |
| Curtailment | **-** | **-** | 14 | 10 | **-** | 3 |
| Settlement | **-** | **-** | - | (46) | **-** | - |
| Recognition of termination benefits | **-** | **-** | 14 | 1 | **-** | - |
| Foreign currency exchange rate change | **-** | **283** | - | (358) | **1** | 1 |
| Benefit obligation at December 31* | **$ 3,236** | **3,845** | 3,416 | 3,445 | **265** | 286 |
| **Accumulated benefit obligation portion of above at December 31:* | *$ 3,076* | *3,404* | *3,246* | *3,067* | | |
| **Change in Fair Value of Plan Assets** | | | | | | |
| Fair value of plan assets at January 1 | **$ 2,081** | **3,068** | 2,606 | 3,063 | **-** | - |
| Actual return on plan assets | **336** | **313** | 133 | 397 | **-** | - |
| Company contributions | **755** | **114** | 214 | 125 | **45** | 44 |
| Plan participant contributions | **-** | **2** | - | 3 | **23** | 24 |
| Benefits paid | **(631)** | **(117)** | (872) | (148) | **(68)** | (68) |
| Foreign currency exchange rate change | **-** | **267** | - | (372) | **-** | - |
| Fair value of plan assets at December 31 | **$ 2,541** | **3,647** | 2,081 | 3,068 | **-** | - |
| **Funded Status** | **$ (695)** | **(198)** | (1,335) | (377) | **(265)** | (286) |

| | Pension Benefits (Millions of Dollars) | | | | Other Benefits | |
|---|---|---|---|---|---|---|
| | **2017** | | 2016 | | **2017** | 2016 |
| | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| **Amounts Recognized in the Consolidated Balance Sheet at December 31** | | | | | | |
| Noncurrent assets | $ **-** | **205** | - | 164 | **-** | - |
| Current liabilities | **(38)** | **(4)** | (101) | (7) | **(45)** | (44) |
| Noncurrent liabilities | **(657)** | **(399)** | (1,234) | (534) | **(220)** | (242) |
| Total recognized | $ **(695)** | **(198)** | (1,335) | (377) | **(265)** | (286) |
| **Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31** | | | | | | |
| Discount rate | **3.55 %** | **2.80** | 3.95 | 3.00 | **3.30** | 3.60 |
| Rate of compensation increase | **4.00** | **3.75** | 4.00 | 3.85 | **-** | - |
| **Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31** | | | | | | |
| Discount rate | **3.80 %** | **3.00** | 3.90 | 3.95 | **3.60** | 3.75 |
| Expected return on plan assets | **6.55** | **5.05** | 7.00 | 5.45 | **-** | - |
| Rate of compensation increase | **4.00** | **3.85** | 4.00 | 4.05 | **-** | - |

For both U.S. and international pensions, the overall expected long-term rate of return is developed from the expected future return of each asset class, weighted by the expected allocation of pension assets to that asset class. We rely on a variety of independent market forecasts in developing the expected rate of return for each class of assets.

Included in accumulated other comprehensive income (loss) at December 31 were the following before-tax amounts that had not been recognized in net periodic benefit cost:

| | Pension Benefits (Millions of Dollars) | | | | Other Benefits | |
|---|---|---|---|---|---|---|
| | **2017** | | 2016 | | **2017** | 2016 |
| | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| Unrecognized net actuarial (gain) loss | $ **588** | **358** | 748 | 479 | **(12)** | (27) |
| Unrecognized prior service cost (credit) | **-** | **(16)** | 4 | (20) | **(249)** | (285) |

| | | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|---|
| | | Pension Benefits | | | | Other Benefits | |
| | | **2017** | | 2016 | | **2017** | 2016 |
| | | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| **Sources of Change in Other Comprehensive Income (Loss)** | | | | | | | |
| Net gain (loss) arising during the period | **$** | **(40)** | **71** | (263) | (232) | **(12)** | 14 |
| Amortization of (gain) loss included in income (loss)* | | **200** | **50** | 288 | 26 | **(3)** | (5) |
| Net change during the period | **$** | **160** | **121** | 25 | (206) | **(15)** | 9 |
| | | | | | | | |
| Prior service credit (cost) arising during the period | **$** | **-** | **2** | - | (4) | **-** | 27 |
| Amortization of prior service cost (credit) included in income (loss) | | **4** | **(6)** | 5 | (6) | **(36)** | (34) |
| Net change during the period | **$** | **4** | **(4)** | 5 | (10) | **(36)** | (7) |

**Includes settlement losses recognized in 2017 and 2016.*

During the year ended December 31, 2016, there was an amendment to the U.S. other postretirement benefit plan. The benefit obligation decreased by $27 million for changes in the plan made to post-65 retiree medical benefits related to updated cost sharing assumption changes for retirees. The $27 million decrease in the benefit obligation resulted in a corresponding increase in other comprehensive income.

Included in accumulated other comprehensive loss at December 31, 2017, were the following before-tax amounts that are expected to be amortized into net periodic benefit cost during 2018:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | Pension Benefits | | Other Benefits |
| | | U.S. | Int'l. | |
| Unrecognized net actuarial (gain) loss | $ | 59 | 36 | (1) |
| Unrecognized prior service credit | | - | (5) | (34) |

For our tax-qualified pension plans with projected benefit obligations in excess of plan assets, the projected benefit obligation, the accumulated benefit obligation, and the fair value of plan assets were $5,634 million, $5,226 million, and $5,113 million, respectively, at December 31, 2017, and $5,498 million, $5,145 million, and $4,208 million, respectively, at December 31, 2016.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $578 million and $503 million, respectively, at December 31, 2017, and were $586 million and $496 million, respectively, at December 31, 2016.

The components of net periodic benefit cost of all defined benefit plans are presented in the following table:

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Pension Benefits | | | | | | Other Benefits | | |
| | **2017** | | 2016 | | 2015 | | **2017** | 2016 | 2015 |
| | **U.S.** | **Int'l.** | U.S. | Int'l. | U.S. | Int'l. | | | |
| **Components of Net Periodic Benefit Cost** | | | | | | | | | |
| Service cost | **$ 89** | **77** | 108 | 76 | 138 | 124 | **2** | 2 | 4 |
| Interest cost | **118** | **103** | 133 | 120 | 161 | 135 | **9** | 13 | 22 |
| Expected return on plan assets | **(132)** | **(158)** | (149) | (147) | (201) | (164) | **-** | - | - |
| Amortization of prior service cost (credit) | **4** | **(6)** | 5 | (6) | 6 | (7) | **(36)** | (34) | (17) |
| Recognized net actuarial loss (gain) | **69** | **50** | 86 | 26 | 115 | 82 | **(3)** | (2) | 2 |
| Settlements | **131** | **-** | 202 | - | 197 | 7 | **-** | - | - |
| Curtailment (gain) loss | **-** | **-** | 14 | - | 35 | (4) | **-** | 1 | 2 |
| Net periodic benefit cost | **$ 279** | **66** | 399 | 69 | 451 | 173 | **(28)** | (20) | 13 |

We recognized pension settlement losses of $131 million in 2017, $202 million in 2016 and $204 million in 2015 as lump-sum benefit payments from certain U.S. and international pension plans exceeded the sum of service and interest costs for those plans and led to recognition of settlement losses.

As part of the 2016 and 2015 restructuring programs, we concluded that actions taken during those years resulted in a significant reduction of future services of active employees primarily in the U.S. qualified pension plan and a U.S. nonqualified supplemental retirement plan. As a result, we recognized an increase in the benefit obligation and a proportionate share of prior service cost from other comprehensive income (loss) as curtailment losses of $15 million and $33 million during the years ended December 31, 2016 and 2015, respectively.

Also as part of the 2016 and 2015 restructuring programs in the U.S. and Europe, we recognized expense for special termination benefits of $15 million during the year ended December 31, 2016, consisting of $14 million in the U.S. and $1 million in Europe, and $124 million during the year ended December 31, 2015, consisting of $46 million in the U.S. and $78 million in Europe. Approximately 62 percent of the 2015 Europe amount was recovered from joint venture partners.

In determining net pension and other postretirement benefit costs, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. For net actuarial gains and losses, we amortize 10 percent of the unamortized balance each year.

We have multiple nonpension postretirement benefit plans for health and life insurance. The health care plans are contributory and subject to various cost sharing features, with participant and company contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the U.S. pre-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 6.25 percent in 2018 that declines to 5 percent by 2023. The measurement of the U.S. post-65 retiree medical accumulated postretirement benefit obligation assumes an ultimate health care cost trend rate of 5 percent achieved in 2018. A one-percentage-point change in the assumed health care cost trend rate would be immaterial to ConocoPhillips.

**Plan Assets**—We follow a policy of broadly diversifying pension plan assets across asset classes and individual holdings. As a result, our plan assets have no significant concentrations of credit risk. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. The target allocations for plan assets are 43 percent equity securities, 50 percent debt securities, 6 percent real estate and 1 percent other. Generally, the plan investments are publicly traded, therefore minimizing liquidity risk in the portfolio.

The following is a description of the valuation methodologies used for the pension plan assets. There have been no changes in the methodologies used at December 31, 2017 and 2016.

- Fair values of equity securities and government debt securities categorized in Level 1 are primarily based on quoted market prices in active markets for identical assets and liabilities.
- Fair values of corporate debt securities, agency and mortgage-backed securities and government debt securities categorized in Level 2 are estimated using recently executed transactions and quoted market prices for similar assets and liabilities in active markets and for identical assets and liabilities in markets that are not active. If there have been no market transactions in a particular fixed income security, its fair value is calculated by pricing models that benchmark the security against other securities with actual market prices. When observable quoted market prices are not available, fair value is based on pricing models that use something other than actual market prices (e.g., observable inputs such as benchmark yields, reported trades and issuer spreads for similar securities), and these securities are categorized in Level 3 of the fair value hierarchy.
- Fair values of investments in common/collective trusts are determined by the issuer of each fund based on the fair value of the underlying assets.
- Fair values of mutual funds are based on quoted market prices, which represent the net asset value of shares held.
- Time deposits are valued at cost, which approximates fair value.
- Cash is valued at cost, which approximates fair value. Fair values of international cash equivalents categorized in Level 2 are valued using observable yield curves, discounting and interest rates. U.S. cash balances held in the form of short-term fund units that are redeemable at the measurement date are categorized as Level 2.
- Fair values of exchange-traded derivatives classified in Level 1 are based on quoted market prices. For other derivatives classified in Level 2, the values are generally calculated from pricing models with market input parameters from third-party sources.
- Fair values of insurance contracts are valued at the present value of the future benefit payments owed by the insurance company to the plans' participants.
- Fair values of real estate investments are valued using real estate valuation techniques and other methods that include reference to third-party sources and sales comparables where available.
- A portion of U.S. pension plan assets is held as a participating interest in an insurance annuity contract, which is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract. The participating interest is classified as Level 3 in the fair value hierarchy as the fair value is determined via a combination of quoted market prices, recently executed transactions, and an actuarial present value computation for contract obligations. At December 31, 2017, the participating interest in the annuity contract was valued at $99 million and consisted of $265 million in debt securities, less $166 million for the accumulated benefit obligation covered by the contract. At December 31, 2016, the participating interest in the annuity contract was valued at $121 million and consisted of $288 million in debt securities, less $167 million for the accumulated benefit obligation covered by the contract. The net change from 2016 to 2017 is due to a decrease in the fair value of the underlying investments of $23 million offset by a decrease in the present value of the contract obligation of $1 million. The participating interest is not available for meeting general pension benefit obligations in the near term. No future company contributions are required and no new benefits are being accrued under this insurance annuity contract.

The fair values of our pension plan assets at December 31, by asset class were as follows:

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | U.S. | | | | | International | | | |
| | | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
| **2017** | | | | | | | | | |
| Equity securities | | | | | | | | | |
| U.S. | **$** | **161** | **-** | **14** | **175** | **440** | **-** | **-** | **440** |
| International | | **178** | **-** | **-** | **178** | **315** | **-** | **-** | **315** |
| Common/collective trusts | | **-** | **-** | **-** | **-** | **-** | **183** | **-** | **183** |
| Mutual funds | | **146** | **-** | **-** | **146** | **292** | **165** | **-** | **457** |
| Debt securities | | | | | | | | | |
| Government | | **-** | **-** | **-** | **-** | **902** | **-** | **-** | **902** |
| Corporate | | **-** | **2** | **-** | **2** | **-** | **-** | **-** | **-** |
| Common/collective trusts | | **-** | **-** | **-** | **-** | **-** | **648** | **-** | **648** |
| Mutual funds | | **-** | **-** | **-** | **-** | **144** | **-** | **-** | **144** |
| Cash and cash equivalents | | **-** | **-** | **-** | **-** | **111** | **-** | **-** | **111** |
| Time deposits | | **-** | **-** | **-** | **-** | **3** | **-** | **-** | **3** |
| Derivatives | | **-** | **-** | **-** | **-** | **5** | **-** | **-** | **5** |
| Real estate | | **-** | **-** | **-** | **-** | **-** | **-** | **123** | **123** |
| Total in fair value hierarchy | **$** | **485** | **2** | **14** | **501** | **2,212** | **996** | **123** | **3,331** |
| | | | | | | | | | |
| Investments measured at net asset value* | | | | | | | | | |
| Equity securities | | | | | | | | | |
| Common/collective trusts | **$** | **-** | **-** | **-** | **805** | **-** | **-** | **-** | **-** |
| Debt securities | | | | | | | | | |
| Corporate | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **172** |
| Agency and mortgage-backed securities | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **15** |
| Common/collective trusts | | **-** | **-** | **-** | **1,042** | **-** | **-** | **-** | **-** |
| Cash and cash equivalents | | **-** | **-** | **-** | **17** | **-** | **-** | **-** | **24** |
| Real estate | | **-** | **-** | **-** | **74** | **-** | **-** | **-** | **94** |
| Total** | **$** | **485** | **2** | **14** | **2,439** | **2,212** | **996** | **123** | **3,636** |

**In accordance with FASB ASC Topic 715, "Compensation—Retirement Benefits," certain investments that are to be measured at fair value using the net asset value per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Change in Fair Value of Plan Assets.*

***Excludes the participating interest in the insurance annuity contract with a net asset value of $99 million and net receivables related to security transactions of $14 million.*

The fair values of our pension plan assets at December 31, by asset class were as follows:

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | U.S. | | | | International | | | | |
| | | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
| 2016 | | | | | | | | | |
| Equity securities | | | | | | | | | |
| U.S. | $ | 632 | - | 14 | 646 | 628 | - | - | 628 |
| International | | 342 | - | - | 342 | 428 | - | - | 428 |
| Common/collective trusts | | - | - | - | - | - | 156 | - | 156 |
| Mutual funds | | 62 | - | - | 62 | 268 | 139 | - | 407 |
| Debt securities | | | | | | | | | |
| Government | | - | 38 | - | 38 | 470 | - | - | 470 |
| Corporate | | - | 54 | 3 | 57 | - | - | - | - |
| Common/collective trusts | | - | - | - | - | - | 385 | - | 385 |
| Mutual funds | | - | - | - | - | 137 | - | - | 137 |
| Cash and cash equivalents | | - | - | - | - | 48 | - | - | 48 |
| Derivatives | | - | - | - | - | 18 | - | - | 18 |
| Real estate | | - | - | - | - | - | - | 111 | 111 |
| Total in fair value hierarchy | $ | 1,036 | 92 | 17 | 1,145 | 1,997 | 680 | 111 | 2,788 |
| | | | | | | | | | |
| Investments measured at net asset value* | | | | | | | | | |
| Equity securities | | | | | | | | | |
| Common/collective trusts | $ | - | - | - | 410 | - | - | - | - |
| Debt securities | | | | | | | | | |
| Corporate | | - | - | - | - | - | - | - | 155 |
| Agency and mortgage-backed securities | | - | - | - | - | - | - | - | 27 |
| Common/collective trusts | | - | - | - | 312 | - | - | - | - |
| Cash and cash equivalents | | - | - | - | 36 | - | - | - | 11 |
| Real estate | | - | - | - | 69 | - | - | - | 76 |
| Total** | $ | 1,036 | 92 | 17 | 1,972 | 1,997 | 680 | 111 | 3,057 |

**In accordance with FASB ASC Topic 715, "Compensation—Retirement Benefits," certain investments that are to be measured at fair value using the net asset value per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Change in Fair Value of Plan Assets.*

***Excludes the participating interest in the insurance annuity contract with a net asset value of $121 million and net payables related to security transactions of $1 million.*

Level 3 activity was not material for all periods.

Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code of 1986, as amended. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2018, we expect to contribute approximately $80 million to our domestic nonqualified pension and postretirement benefit plans and $130 million to our international qualified and nonqualified pension and postretirement benefit plans.

The following benefit payments, which are exclusive of amounts to be paid from the insurance annuity contract and which reflect expected future service, as appropriate, are expected to be paid:

| | Millions of Dollars | | |
|---|---|---|---|
| | Pension Benefits | | Other Benefits |
| | U.S. | Int'l. | |
| 2018 | $ 383 | 122 | 40 |
| 2019 | 302 | 141 | 37 |
| 2020 | 290 | 135 | 34 |
| 2021 | 286 | 144 | 31 |
| 2022 | 291 | 144 | 28 |
| 2023–2027 | 1,247 | 780 | 91 |

**Severance Accrual**
As a result of selling our 50 percent nonoperated interest in the FCCL Partnership and the majority of our western Canada gas assets, as well as our interest in the San Juan Basin, a reduction in our overall employee workforce occurred during 2017. Severance accruals of $65 million were recorded in 2017. The following table summarizes our severance accrual activity for the year ended December 31, 2017:

| | Millions of Dollars |
|---|---|
| Balance at December 31, 2016 | $ 80 |
| Accruals | **65** |
| Benefit payments | **(93)** |
| Foreign currency translation adjustments | **1** |
| Balance at December 31, 2017 | **$ 53** |

Of the remaining balance at December 31, 2017, $30 million is classified as short-term.

**Defined Contribution Plans**
Most U.S. employees are eligible to participate in the ConocoPhillips Savings Plan (CPSP). Employees can deposit up to 75 percent of their eligible pay, subject to statutory limits, in the CPSP to a choice of approximately 34 investment options. Employees who participate in the CPSP and contribute 1 percent of their eligible pay receive a 6 percent company cash match with a potential company discretionary cash contribution of up to 6 percent. Company contributions charged to expense for the CPSP and predecessor plans were $51 million in 2017, $58 million in 2016, and $109 million in 2015.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense recognized for these international plans was approximately $35 million in 2017, $44 million in 2016, and $55 million in 2015.

**Share-Based Compensation Plans**
The 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (the Plan) was approved by shareholders in May 2014. Over its 10-year life, the Plan allows the issuance of up to 79 million shares of our common stock for compensation to our employees and directors; however, as of the effective date of the Plan, (i) any shares of common stock available for future awards under the prior plans and (ii) any shares of common stock represented by awards granted under the prior plans that are forfeited, expire or are cancelled without delivery of shares of common stock or which result in the forfeiture of shares of common stock back to the company shall be available for awards under the Plan, and no new awards shall be granted under the prior plans. Of the 79 million shares available for issuance under the Plan, no more than 40 million shares of common stock are available for incentive stock options. The Human Resources and Compensation Committee

of our Board of Directors is authorized to determine the types, terms, conditions and limitations of awards granted. Awards may be granted in the form of, but not limited to, stock options, restricted stock units and performance share units to employees and non-employee directors who contribute to the company's continued success and profitability.

Total share-based compensation expense is measured using the grant date fair value for our equity-classified awards and the settlement date fair value for our liability-classified awards. We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award); or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement, but not less than six months, as this is the minimum period of time required for an award to not be subject to forfeiture. Our share-based compensation programs generally provide accelerated vesting (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. Some of our share-based awards vest ratably (i.e., portions of the award vest at different times) while some of our awards cliff vest (i.e., all of the award vests at the same time). We recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

**Compensation Expense—**Total share-based compensation expense recognized in loss and the associated tax benefit for the years ended December 31 were as follows:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2017** | 2016 | 2015 |
| Compensation cost | $ **227** | 272 | 362 |
| Tax benefit | **76** | 92 | 123 |

**Stock Options**—Stock options granted under the provisions of the Plan and prior plans permit purchase of our common stock at exercise prices equivalent to the average market price of ConocoPhillips common stock on the date the options were granted. The options have terms of 10 years and generally vest ratably, with one-third of the options awarded vesting and becoming exercisable on each anniversary date following the date of grant. Options awarded to certain employees already eligible for retirement vest within six months of the grant date, but those options do not become exercisable until the end of the normal vesting period.

The fair market values of the options granted over the past three years were measured on the date of grant using the Black-Scholes-Merton option-pricing model. The weighted-average assumptions used were as follows:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Assumptions used | | | |
| Risk-free interest rate | **2.24 %** | 1.55 | 1.79 |
| Dividend yield | **4.00 %** | 4.00 | 4.00 |
| Volatility factor | **28.12 %** | 26.80 | 23.32 |
| Expected life (years) | **6.39** | 6.37 | 5.79 |

There were no ranges in the assumptions used to determine the fair market values of our options granted over the past three years.

We believe our historical volatility for periods prior to the 2012 separation of our Downstream businesses is no longer relevant in estimating expected volatility. For 2015 through 2017, expected volatility was based on the weighted-average blend of the company's historical stock price volatility from May 1, 2012 (the date of separation of our Downstream businesses) through the stock option grant date and the average historical stock price volatility of a group of peer companies for the expected term of the options.

The following summarizes our stock option activity for the year ended December 31, 2017:

| | Options | Weighted-Average Exercise Price | Weighted-Average Grant Date Fair Value | Millions of Dollars Aggregate Intrinsic Value |
|---|---|---|---|---|
| Outstanding at December 31, 2016 | 23,712,112 | $ 52.14 | | $ 128 |
| Granted | **2,670,200** | **49.76** | **$ 9.18** | |
| Exercised | **(360,396)** | **37.24** | | **4** |
| Forfeited | **(50,696)** | **48.55** | | |
| Expired or cancelled | **(1,248,417)** | **50.61** | | |
| **Outstanding at December 31, 2017** | **24,722,803** | **$ 52.18** | | **$ 177** |
| **Vested at December 31, 2017** | **23,424,010** | **$ 52.52** | | **$ 162** |
| **Exercisable at December 31, 2017** | **18,074,088** | **$ 54.34** | | **$ 101** |

The weighted-average remaining contractual term of outstanding options, vested options and exercisable options at December 31, 2017, was 5.52 years, 5.36 years and 4.50 years, respectively. The weighted-average grant date fair value of stock option awards granted during 2016 and 2015 was $5.39 and $9.54, respectively. The aggregate intrinsic value of options exercised was zero in 2016 and $10 million in 2015.

During 2017, we received $13 million in cash and realized a tax benefit of $12 million from the exercise of options. At December 31, 2017, the remaining unrecognized compensation expense from unvested options was $5 million, which will be recognized over a weighted-average period of 1.33 years, the longest period being 2.12 years.

Beginning in 2018, stock option grants will be discontinued and replaced with three-year, time-vested restricted stock units which will be cash-settled.

**Stock Unit Program—**Generally, restricted stock units are granted annually under the provisions of the Plan. Restricted stock units granted prior to 2013 generally vest ratably in three equal annual installments beginning on the third anniversary of the grant date. Beginning in 2013, restricted stock units granted will vest in an aggregate installment on the third anniversary of the grant date. In addition, beginning in 2012, restricted stock units granted under the Plan for a variable long-term incentive program vest ratably in three equal annual installments beginning on the first anniversary of the grant date. Restricted stock units are also granted ad hoc to attract or retain key personnel, and the terms and conditions under which these restricted stock units vest vary by award. Upon vesting, the restricted stock units are settled by issuing one share of ConocoPhillips common stock per unit. Units awarded to retirement eligible employees vest six months from the grant date; however, those units are not issued as common stock until the earlier of separation from the company or the end of the regularly scheduled vesting period. Until issued as stock, most recipients of the restricted stock units receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. The grant date fair market value of these restricted stock units is deemed equal to the average ConocoPhillips stock price on the grant date. The grant date fair market value of units that do not receive a dividend equivalent while unvested is deemed equal to the average ConocoPhillips stock price on the grant date, less the net present value of the dividends that will not be received.

The following summarizes our stock unit activity for the year ended December 31, 2017:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2016 | 8,507,504 | $ 48.65 | |
| Granted | **3,011,903** | **48.77** | |
| Forfeited | **(372,871)** | **45.99** | |
| Issued | **(3,319,684)** | | **$ 159** |
| **Outstanding at December 31, 2017** | **7,826,852** | **$ 45.75** | |
| **Not Vested at December 31, 2017** | **5,396,027** | **$ 45.58** | |

At December 31, 2017, the remaining unrecognized compensation cost from the unvested units was $93 million, which will be recognized over a weighted-average period of 1.67 years, the longest period being 2.75 years. The weighted-average grant date fair value of stock unit awards granted during 2016 and 2015 was $32.15 and $65.40, respectively. The total fair value of stock units issued during 2016 and 2015 was $191 million and $316 million, respectively.

**Performance Share Program**—Under the Plan, we also annually grant restricted performance share units (PSUs) to senior management. These PSUs are authorized three years prior to their effective grant date (the performance period). Compensation expense is initially measured using the average fair market value of ConocoPhillips common stock and is subsequently adjusted, based on changes in the ConocoPhillips stock price through the end of each subsequent reporting period, through the grant date for stock-settled awards and the settlement date for cash-settled awards.

*Stock-Settled*

For performance periods beginning before 2009, PSUs do not vest until the employee becomes eligible for retirement by reaching age 55 with five years of service, and restrictions do not lapse until the employee separates from the company. With respect to awards for performance periods beginning in 2009 through 2012, PSUs do not vest until the earlier of the date the employee becomes eligible for retirement by reaching age 55 with five years of service or five years after the grant date of the award, and restrictions do not lapse until the earlier of the employee's separation from the company or five years after the grant date (although recipients can elect to defer the lapsing of restrictions until separation). We recognize compensation expense for these awards beginning on the grant date and ending on the date the PSUs are scheduled to vest. Since these awards are authorized three years prior to the grant date, for employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Until issued as stock, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. Beginning in 2013, PSUs authorized for future grants will vest, absent employee election to defer, upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending on the conclusion of the performance period. PSUs are settled by issuing one share of ConocoPhillips common stock per unit.

The following summarizes our stock-settled Performance Share Program activity for the year ended December 31, 2017:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2016 | 3,889,524 | $ 51.93 | |
| Granted | **30,953** | **49.76** | |
| Issued | **(1,167,012)** | | **$ 57** |
| **Outstanding at December 31, 2017** | **2,753,465** | **$ 50.79** | |
| **Not Vested at December 31, 2017** | **67,083** | **$ 48.17** | |

At December 31, 2017, the remaining unrecognized compensation cost from unvested stock-settled performance share awards was $1 million, which will be recognized over a weighted-average period of 2.00 years, the longest period being 3.00 years. The weighted-average grant date fair value of stock-settled PSUs granted during 2016 and 2015 was $33.13 and $69.25, respectively. The total fair value of stock-settled PSUs issued during 2016 and 2015 was $17 million and $25 million, respectively.

*Cash-Settled*

In connection with and immediately following the separation of our Downstream businesses in 2012, grants of new PSUs, subject to a shortened performance period, were authorized. Once granted, these PSUs vest, absent employee election to defer, on the earlier of five years after the grant date of the award or the date the employee becomes eligible for retirement. For employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Otherwise, we recognize compensation expense beginning on the grant date and ending on the date the PSUs are scheduled to vest. These PSUs are settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and thus are classified as liabilities on the balance sheet. Until settlement occurs, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to compensation expense.

Beginning in 2013, PSUs authorized for future grants will vest upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending at the conclusion of the performance period. These PSUs will be settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and are classified as liabilities on the balance sheet. During the performance period, recipients of the PSUs do not receive a quarterly cash payment of a dividend equivalent, but after the performance period ends, until settlement in cash occurs, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to compensation expense.

The following summarizes our cash-settled Performance Share Program activity for the year ended December 31, 2017:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2016 | 1,274,762 | $ 50.39 | |
| Granted | **456,909** | **49.76** | |
| Settled | **(517,138)** | | **$ 24** |
| **Outstanding at December 31, 2017** | **1,214,533** | **$ 55.19** | |
| **Not Vested at December 31, 2017** | **122,228** | **$ 55.19** | |

At December 31, 2017, the remaining unrecognized compensation cost from unvested cash-settled performance share awards was $2 million, which will be recognized over a weighted-average period of 1.64 years, the longest period being 2.13 years. The weighted-average grant date fair value of cash-settled PSUs granted during 2016 and 2015 was $33.13 and $69.25, respectively. The total fair value of cash-settled performance share awards settled during 2016 and 2015 was $31 million and $6 million, respectively.

From inception of the Performance Share Program through 2013, approved PSU awards were granted after the conclusion of performance periods. Beginning in February 2014, initial target PSU awards are issued near the beginning of new performance periods. These initial target PSU awards will terminate at the end of the performance periods and will be settled after the performance periods have ended. Also in 2014, initial target PSU awards were issued for open performance periods that began in prior years. For the open performance period beginning in 2012, the initial target PSU awards terminated at the end of the three-year performance period and were replaced with approved PSU awards. For the open performance period beginning in 2013, the initial target PSU awards terminated at the end of the three-year performance period and were settled after the performance period ended. There is no effect on recognition of compensation expense.

**Other**—In addition to the above active programs, we have outstanding shares of restricted stock and restricted stock units that were either issued as part of our non-employee director compensation program for current and former members of the company's Board of Directors or as part of an executive compensation program that has been discontinued. Generally, the recipients of the restricted shares or units receive a quarterly dividend or dividend equivalent.

The following summarizes the aggregate activity of these restricted shares and units for the year ended December 31, 2017:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2016 | 1,317,964 | $ 33.16 | |
| Granted | **87,980** | **48.87** | |
| Cancelled | **(24,486)** | **21.37** | |
| Issued | **(80,418)** | | **$ 4** |
| **Outstanding at December 31, 2017** | **1,301,040** | **$ 32.66** | |
| **Not Vested at December 31, 2017** | **-** | | |

At December 31, 2017, all outstanding restricted stock and restricted stock units were fully vested and there was no remaining compensation cost to be recorded. The weighted-average grant date fair value of awards granted during 2016 and 2015 was $40.36 and $58.66, respectively. The total fair value of awards issued during 2016 and 2015 was $2 million and $3 million, respectively.

## Note 18—Income Taxes

Income tax benefits included in net loss were:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| **Income Taxes** | | | | |
| Federal | | | | |
| Current | $ | **79** | (9) | (718) |
| Deferred | | **(3,046)** | (1,634) | (1,443) |
| Foreign | | | | |
| Current | | **1,729** | 393 | 745 |
| Deferred | | **(510)** | (519) | (1,315) |
| State and local | | | | |
| Current | | **51** | (135) | 8 |
| Deferred | | **(125)** | (67) | (145) |
| | $ | **(1,822)** | (1,971) | (2,868) |

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Major components of deferred tax liabilities and assets at December 31 were:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2017** | 2016 |
| **Deferred Tax Liabilities** | | | |
| PP&E and intangibles | $ | **9,692** | 15,099 |
| Investments in joint ventures | | **-** | 933 |
| Inventory | | **61** | 36 |
| Deferred state income tax | | **178** | 203 |
| Other | | **464** | 486 |
| Total deferred tax liabilities | | **10,395** | 16,757 |
| **Deferred Tax Assets** | | | |
| Benefit plan accruals | | **786** | 1,280 |
| Asset retirement obligations and accrued environmental costs | | **3,060** | 3,514 |
| Investments in joint ventures | | **57** | - |
| Other financial accruals and deferrals | | **166** | 317 |
| Loss and credit carryforwards | | **2,310** | 3,522 |
| Other | | **152** | 250 |
| Total deferred tax assets | | **6,531** | 8,883 |
| Less: valuation allowance | | **(1,254)** | (675) |
| Net deferred tax assets | | **5,277** | 8,208 |
| Net deferred tax liabilities | $ | **5,118** | 8,549 |

At December 31, 2017, noncurrent assets and liabilities included deferred taxes of $164 million and $5,282 million, respectively. At December 31, 2016, noncurrent assets and liabilities included deferred taxes of $400 million and $8,949 million, respectively.

At December 31, 2017, the components of our loss and credit carryforwards before and after consideration of the applicable valuation allowances are:

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | | Gross Deferred Tax Asset | Net Deferred Tax Asset After Valuation Allowance | Expiration of Net Deferred Tax Asset |
| U.S. foreign tax credits | $ | 856 | 567 | 2025-2027 |
| U.S. general business credits | | 227 | 227 | 2036-2037 |
| State net operating losses and tax credits | | 420 | - | |
| Foreign net operating losses and tax credits | | 807 | 786 | Post 2025 |
| | $ | 2,310 | 1,580 | |

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2017, valuation allowances increased a total of $579 million. This increase primarily relates to the expected realization of certain deferred tax assets, including foreign tax credits; U.S. tax basis associated with foreign assets; and state net operating losses and tax credits not expected to be realized. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects deferred tax assets, net of valuation allowance, will primarily be realized as offsets to reversing deferred tax liabilities.

At December 31, 2017, unremitted income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $2,600 million. Deferred income taxes have not been provided on this amount, as we do not plan to initiate any action that would require the payment of income taxes. The estimated amount of additional tax that would be payable on this income if distributed is approximately $130 million.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2017, 2016 and 2015:

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| Balance at January 1 | **$** | **381** | 459 | 442 |
| Additions based on tax positions related to the current year | | **612** | 32 | 54 |
| Additions for tax positions of prior years | | **109** | 19 | 4 |
| Reductions for tax positions of prior years | | **(129)** | (118) | (37) |
| Settlements | | **(5)** | (9) | (4) |
| Lapse of statute | | **(86)** | (2) | - |
| Balance at December 31 | **$** | **882** | 381 | 459 |

Included in the balance of unrecognized tax benefits for 2017, 2016 and 2015 were $882 million, $359 million and $354 million, respectively, which, if recognized, would impact our effective tax rate. The balance of unrecognized tax benefits increased in 2017 mainly due to the recognition of a U.S. worthless securities deduction that we do not believe will generate a cash tax benefit.

At December 31, 2017, 2016 and 2015, accrued liabilities for interest and penalties totaled $54 million, $54 million and $79 million, respectively, net of accrued income taxes. Interest and penalties resulted in no impact to earnings in 2017, a benefit to earnings of $18 million in 2016, and a reduction to earnings of $11 million in 2015.

We and our subsidiaries file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions are generally complete as follows: United Kingdom (2014), Canada (2009), United States (2010) and Norway (2016). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world. As a consequence, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

The amounts of U.S. and foreign income (loss) before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes, were:

| | | Millions of Dollars | | | Percent of Pre-Tax Income (Loss) | | |
|---|---|---|---|---|---|---|---|
| | | **2017** | 2016 | 2015 | **2017** | 2016 | 2015 |
| Loss before income taxes | | | | | | | |
| United States | $ | **(5,250)** | (4,410) | (4,150) | **200.8 %** | 79.7 | 57.3 |
| Foreign | | **2,635** | (1,120) | (3,089) | **(100.8)** | 20.3 | 42.7 |
| | $ | **(2,615)** | (5,530) | (7,239) | **100.0 %** | 100.0 | 100.0 |
| | | | | | | | |
| Federal statutory income tax | $ | **(915)** | (1,936) | (2,534) | **35.0 %** | 35.0 | 35.0 |
| Non-U.S. effective tax rates | | **625** | 361 | 301 | **(23.9)** | (6.5) | (4.2) |
| Impact of U.S. tax legislation | | **(852)** | - | - | **32.6** | - | - |
| Canada disposition | | **(1,277)** | - | - | **48.8** | - | - |
| Recovery of outside basis | | **(962)** | (60) | (491) | **36.8** | 1.1 | 6.8 |
| Adjustment to tax reserves | | **881** | 55 | 42 | **(33.7)** | (1.0) | (0.6) |
| APLNG impairment | | **834** | - | 525 | **(31.9)** | - | (7.3) |
| State income tax | | **(84)** | (122) | (85) | **3.2** | 2.2 | 1.2 |
| Enhanced oil recovery credit | | **(68)** | (62) | - | **2.6** | 1.1 | - |
| U.K. rate change | | **-** | (161) | (555) | **-** | 2.9 | 7.7 |
| Canada rate change | | **-** | - | 129 | **-** | - | (1.8) |
| U.S. fair value election | | **-** | - | (185) | **-** | - | 2.6 |
| Other | | **(4)** | (46) | (15) | **0.2** | 0.8 | 0.2 |
| | $ | **(1,822)** | (1,971) | (2,868) | **69.7 %** | 35.6 | 39.6 |

The increase in the effective tax rate for 2017 was primarily due to the impact of the Tax Cuts and Jobs Act (Tax Legislation) and the impact of the Canada disposition, partially offset by the impact of the APLNG impairment and our mix of income among taxing jurisdictions.

The Tax Legislation, enacted on December 22, 2017, reduces the U.S. federal corporate tax rate from 35 percent to 21 percent, requires companies to pay a one-time transition tax on earnings of certain foreign subsidiaries that were previously tax deferred and creates new taxes on certain foreign-sourced earnings. At December 31, 2017, we have not completed our accounting for the tax effects of enactment of the Tax Legislation; however, as described below, we have made a reasonable estimate of the effects on our existing deferred tax balances and the one-time transition tax and recorded a provisional tax benefit of $852 million.

*Provisional Amount—Deferred tax assets and liabilities*

In the fourth quarter of 2017, we remeasured certain U.S. deferred tax assets and liabilities based on the rates at which they are expected to reverse in the future, which is generally 21 percent. However, we are still analyzing certain aspects of the Tax Legislation and refining our calculations, which could potentially affect the measurement of these balances or potentially give rise to new deferred tax amounts. The provisional amount recorded related to the remeasurement of our U.S. deferred tax balance was a tax benefit of $908 million.

*Provisional Amount—Foreign tax effects*

The one-time transition tax is based on our total post-1986 earnings and profits which we have previously deferred from U.S. income taxes. We reasonably estimate that we will not incur a one-time transition tax. This assumption may change when we finalize the calculation of post-1986 foreign earnings and profits, previously deferred from U.S. federal taxation, and finalize the amounts held in cash or other specified assets. As a result of the Tax Legislation, we have removed the indefinite reinvestment assertion on one of our foreign subsidiaries and recorded a tax expense of $56 million in the fourth quarter of 2017.

Our effective tax rate in 2017 was favorably impacted by a tax benefit of $1,277 million related to the Canada disposition. This tax benefit was primarily associated with a deferred tax recovery related to the Canadian capital gains exclusion component of the 2017 Canada disposition and the recognition of previously unrealizable Canadian capital asset tax basis. The Canada disposition, along with the associated restructuring of our Canadian operations, may generate an additional tax benefit of $822 million. However, since we believe it is not likely we will receive a corresponding cash tax savings, this $822 million benefit has been offset by a full tax reserve. See Note 4—Assets Held for Sale, Sold or Acquired for additional information on our Canada disposition.

The impairment of our APLNG investment in the second quarter of 2017 did not generate a tax benefit. See the "APLNG" section of Note 5—Investments, Loans and Long-Term Receivables, for information on the impairment of our APLNG investment.

The decrease in the effective tax rate for 2016 was primarily due to our mix of income among taxing jurisdictions, reduced net tax benefit from the tax law changes discussed below, and the absence of a tax benefit associated with electing the fair market value method of apportioning interest expense for prior years.

In the United Kingdom, legislation was enacted on September 15, 2016, to decrease the overall U.K. upstream corporation tax rate from 50 percent to 40 percent effective January 1, 2016. As a result, we recorded a $161 million net tax benefit related to the remeasurement of our U.K. deferred tax balance in 2016.

In the United Kingdom, legislation was enacted on March 26, 2015, to decrease the overall U.K. upstream corporation tax rate from 62 percent to 50 percent effective January 1, 2015. As a result, we recorded a $555 million net tax benefit related to the remeasurement of our U.K. deferred tax balance in 2015.

In Canada, legislation was enacted on June 29, 2015, to increase the overall Canadian corporation tax rate from 25 percent to 27 percent effective July 1, 2015. As a result, we recorded a $129 million net tax expense related to the remeasurement of our Canadian deferred tax balance in 2015.

In December 2015, we filed refund claims for prior years electing the fair market value method of apportioning interest in the United States. As a result, we recorded a $185 million tax benefit associated with these refund claims in 2015.

Certain operating losses in jurisdictions outside of the U.S. only yield a tax benefit in the U.S. as a worthless security deduction. For 2017, 2016 and 2015 the amount of the tax benefit was $962 million, $60 million and $491 million, respectively.

## Note 19—Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss in the equity section of the balance sheet included:

| | Millions of Dollars | | | | |
|---|---|---|---|---|---|
| | | Defined Benefit Plans | Net Unrealized Loss on Securities | Foreign Currency Translation | Accumulated Other Comprehensive Loss |
| December 31, 2014 | $ | (1,261) | - | (641) | (1,902) |
| Other comprehensive income (loss) | | 818 | - | (5,163) | (4,345) |
| December 31, 2015 | | (443) | - | (5,804) | (6,247) |
| Other comprehensive income (loss) | | (104) | - | 158 | 54 |
| December 31, 2016 | | (547) | - | (5,646) | (6,193) |
| Other comprehensive income (loss) | | **147** | **(58)** | **586** | **675** |
| **December 31, 2017** | **$** | **(400)** | **(58)** | **(5,060)** | **(5,518)** |

There were no items within accumulated other comprehensive loss related to noncontrolling interests.

The following table summarizes reclassifications out of accumulated other comprehensive loss during the years ended December 31:

| | Millions of Dollars | | |
|---|---|---|---|
| | | **2017** | 2016 |
| Defined Benefit Plans | **$** | **135** | 179 |
| *Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:* | *$* | *74* | *95* |
| *See Note 17—Employee Benefit Plans, for additional information.* | | | |

## Note 20—Cash Flow Information

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| **Noncash Investing Activities** | | | | |
| Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations | **$** | **(37)** | (1,017) | 402 |
| **Cash Payments (Receipts)** | | | | |
| Interest | **$** | **1,163** | 1,151 | 920 |
| Income taxes | | **1,168** | (318) * | 523 * |
| **Net Sales (Purchases) of Short-Term Investments** | | | | |
| Short-term investments purchased | **$** | **(6,617)** | (1,753) | - |
| Short-term investments sold | | **4,827** | 1,702 | - |
| | **$** | **(1,790)** | (51) | - |

**Net of $585 million and $642 million in 2016 and 2015, respectively, related to refunds received from the Internal Revenue Service.*

**Note 21—Other Financial Information**

| | Millions of Dollars | | |
|---|---|---|---|
| | **2017** | 2016 | 2015 |
| **Interest and Debt Expense** | | | |
| Incurred | | | |
| Debt | $ **1,114** | 1,279 | 1,130 |
| Other | **103** | 123 | 84 |
| | **1,217** | 1,402 | 1,214 |
| Capitalized | **(119)** | (157) | (294) |
| Expensed | $ **1,098** | 1,245 | 920 |
| | | | |
| **Other Income** | | | |
| Interest income | $ **112** | 57 | 45 |
| Other, net | **417** | 198 | 80 |
| | $ **529** | 255 | 125 |
| | | | |
| **Research and Development Expenditures**—expensed | $ **100** | 116 | 222 |
| | | | |
| **Shipping and Handling Costs*** | $ **1,058** | 1,139 | 1,181 |

**Amounts included in production and operating expenses.*

| | | | |
|---|---|---|---|
| **Foreign Currency Transaction (Gains) Losses**—after-tax | | | |
| Alaska | $ **-** | - | - |
| Lower 48 | **-** | - | - |
| Canada | **3** | 1 | - |
| Europe and North Africa | **7** | (7) | (22) |
| Asia Pacific and Middle East | **23** | (9) | (78) |
| Other International | **1** | 7 | (9) |
| Corporate and Other | **(3)** | (18) | 45 |
| | $ **31** | (26) | (64) |

| | Millions of Dollars | |
|---|---|---|
| | **2017** | 2016 |
| **Properties, Plants and Equipment** | | |
| Proved properties | $ **102,044** | 119,970 |
| Unproved properties | **4,491** | 5,150 |
| Other | **3,896** | 6,286 |
| Gross properties, plants and equipment | **110,431** | 131,406 |
| Less: Accumulated depreciation, depletion and amortization | **(64,748)** | (73,075) |
| Net properties, plants and equipment | $ **45,683** | 58,331 |

**Note 22—Related Party Transactions**

Our related parties primarily include equity method investments and certain trusts for the benefit of employees.

Significant transactions with our equity affiliates were:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| Operating revenues and other income | $ | **107** | 133 | 118 |
| Purchases | | **99** | 101 | 97 |
| Operating expenses and selling, general and administrative expenses | | **59** | 63 | 62 |
| Net interest (income) expense* | | **(13)** | (12) | (9) |

**We paid interest to, or received interest from, various affiliates. See Note 5—Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.*

The table above includes transactions with the FCCL Partnership through the date of the sale. See Note 5—Investments, Loans and Long-Term Receivables, for additional information.

**Note 23—Segment Disclosures and Related Information**

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, premiums on early retirement of debt, corporate overhead and certain technology activities, including licensing revenues. Corporate assets include all cash and cash equivalents and short-term investments.

We evaluate performance and allocate resources based on net income (loss) attributable to ConocoPhillips. Segment accounting policies are the same as those in Note 1—Accounting Policies. Intersegment sales are at prices that approximate market.

**Analysis of Results by Operating Segment**

| | | Millions of Dollars | |
|---|---|---|---|
| | **2017** | 2016 | 2015 |
| **Sales and Other Operating Revenues** | | | |
| Alaska | $ **4,224** | 3,681 | 4,351 |
| Lower 48 | **12,968** | 10,719 | 11,976 |
| Intersegment eliminations | **(4)** | (17) | (63) |
| Lower 48 | **12,964** | 10,702 | 11,913 |
| Canada | **3,178** | 2,192 | 2,454 |
| Intersegment eliminations | **(559)** | (218) | (318) |
| Canada | **2,619** | 1,974 | 2,136 |
| Europe and North Africa | **5,181** | 3,462 | 6,110 |
| Intersegment eliminations | **-** | - | (4) |
| Europe and North Africa | **5,181** | 3,462 | 6,106 |
| Asia Pacific and Middle East | **4,014** | 3,705 | 4,746 |
| Intersegment eliminations | **-** | - | (1) |
| Asia Pacific and Middle East | **4,014** | 3,705 | 4,745 |
| Other International | **-** | - | 1 |
| Corporate and Other | **104** | 169 | 312 |
| Consolidated sales and other operating revenues | $ **29,106** | 23,693 | 29,564 |
| | | | |
| **Depreciation, Depletion, Amortization and Impairments** | | | |
| Alaska | $ **1,026** | 868 | 690 |
| Lower 48 | **6,693** | 4,358 | 4,227 |
| Canada | **461** | 975 | 788 |
| Europe and North Africa | **1,313** | 1,253 | 2,565 |
| Asia Pacific and Middle East | **3,819** | 1,606 | 2,981 |
| Other International | **-** | 1 | - |
| Corporate and Other | **134** | 140 | 107 |
| Consolidated depreciation, depletion, amortization and impairments | $ **13,446** | 9,201 | 11,358 |

In 2017, sales by our Lower 48, Alaska and Canada segments to a certain refining company accounted for approximately $3 billion or 11 percent of our total consolidated sales and other operating revenues.

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| **Equity in Earnings of Affiliates** | | | | |
| Alaska | $ | **7** | 9 | 4 |
| Lower 48 | | **5** | (6) | (5) |
| Canada | | **197** | 89 | 78 |
| Europe and North Africa | | **10** | 22 | 23 |
| Asia Pacific and Middle East | | **553** | (51) | 550 |
| Other International | | **-** | - | 8 |
| Corporate and Other | | **-** | (11) | (3) |
| Consolidated equity in earnings of affiliates | $ | **772** | 52 | 655 |
| | | | | |
| **Income Taxes** | | | | |
| Alaska | $ | **(689)** | (59) | (71) |
| Lower 48 | | **(2,453)** | (1,328) | (1,119) |
| Canada | | **(616)** | (383) | (223) |
| Europe and North Africa | | **1,165** | (46) | (854) |
| Asia Pacific and Middle East | | **351** | 306 | 467 |
| Other International | | **21** | (40) | (456) |
| Corporate and Other | | **399** | (421) | (612) |
| Consolidated income taxes | $ | **(1,822)** | (1,971) | (2,868) |
| | | | | |
| **Net Income (Loss) Attributable to ConocoPhillips** | | | | |
| Alaska | $ | **1,466** | 319 | 4 |
| Lower 48 | | **(2,371)** | (2,257) | (1,932) |
| Canada | | **2,564** | (935) | (1,044) |
| Europe and North Africa | | **553** | 394 | 409 |
| Asia Pacific and Middle East | | **(1,098)** | 209 | (463) |
| Other International | | **167** | (16) | (593) |
| Corporate and Other | | **(2,136)** | (1,329) | (809) |
| Consolidated net loss attributable to ConocoPhillips | $ | **(855)** | (3,615) | (4,428) |
| | | | | |
| **Investments In and Advances To Affiliates** | | | | |
| Alaska | $ | **56** | 58 | 61 |
| Lower 48 | | **402** | 426 | 455 |
| Canada | | **-** | 8,784 | 8,165 |
| Europe and North Africa | | **55** | 62 | 70 |
| Asia Pacific and Middle East | | **9,077** | 11,611 | 11,780 |
| Other International | | **-** | - | - |
| Corporate and Other | | **-** | 4 | 15 |
| Consolidated investments in and advances to affiliates | $ | **9,590** | 20,945 | 20,546 |

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2017** | 2016 | 2015 |
| **Total Assets** | | | | |
| Alaska | $ | **12,108** | 12,314 | 12,555 |
| Lower 48 | | **14,632** | 22,673 | 26,932 |
| Canada | | **6,214** | 17,548 | 17,221 |
| Europe and North Africa | | **11,870** | 11,727 | 13,703 |
| Asia Pacific and Middle East | | **16,985** | 20,451 | 22,318 |
| Other International | | **97** | 97 | 282 |
| Corporate and Other | | **11,456** | 4,962 | 4,473 |
| Consolidated total assets | $ | **73,362** | 89,772 | 97,484 |
| | | | | |
| **Capital Expenditures and Investments** | | | | |
| Alaska | $ | **815** | 883 | 1,352 |
| Lower 48 | | **2,136** | 1,262 | 3,765 |
| Canada | | **202** | 698 | 1,255 |
| Europe and North Africa | | **872** | 1,020 | 1,573 |
| Asia Pacific and Middle East | | **482** | 838 | 1,812 |
| Other International | | **21** | 104 | 173 |
| Corporate and Other | | **63** | 64 | 120 |
| Consolidated capital expenditures and investments | $ | **4,591** | 4,869 | 10,050 |
| | | | | |
| **Interest Income and Expense** | | | | |
| Interest income | | | | |
| Corporate | $ | **101** | 47 | 36 |
| Lower 48 | | **-** | - | - |
| Europe and North Africa | | **2** | 2 | 2 |
| Asia Pacific and Middle East | | **9** | 8 | 6 |
| Other International | | **-** | - | 1 |
| Interest and debt expense | | | | |
| Corporate | $ | **1,098** | 1,245 | 920 |
| | | | | |
| **Sales and Other Operating Revenues by Product** | | | | |
| Crude oil | $ | **13,260** | 10,801 | 12,830 |
| Natural gas | | **10,773** | 9,401 | 11,888 |
| Natural gas liquids | | **1,102** | 837 | 952 |
| Other* | | **3,971** | 2,654 | 3,894 |
| Consolidated sales and other operating revenues by product | $ | **29,106** | 23,693 | 29,564 |

**Includes LNG and bitumen.*

## Geographic Information

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Sales and Other Operating Revenues[1] | | | Long-Lived Assets[2] | | |
| | **2017** | 2016 | 2015 | **2017** | 2016 | 2015 |
| United States | $ **17,204** | 14,400 | 16,284 | **23,623** | 32,949 | 37,445 |
| Australia[3] | **1,448** | 1,353 | 2,127 | **9,657** | 12,259 | 12,788 |
| Canada | **2,619** | 1,974 | 2,136 | **5,613** | 16,846 | 16,766 |
| China | **712** | 551 | 782 | **1,275** | 1,372 | 1,647 |
| Indonesia | **757** | 938 | 1,165 | **758** | 856 | 1,191 |
| Malaysia | **1,103** | 735 | 598 | **2,736** | 3,323 | 3,599 |
| Norway | **2,348** | 1,645 | 2,107 | **6,154** | 6,228 | 6,933 |
| United Kingdom | **2,248** | 1,816 | 4,005 | **3,335** | 3,209 | 4,154 |
| Other foreign countries | **667** | 281 | 360 | **2,122** | 2,234 | 2,469 |
| Worldwide consolidated | $ **29,106** | 23,693 | 29,564 | **55,273** | 79,276 | 86,992 |

*(1)Sales and other operating revenues are attributable to countries based on the location of the selling operation.*
*(2)Defined as net PP&E plus investments in and advances to affiliated companies.*
*(3)Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.*

## Note 24—New Accounting Standards

In May 2014, the FASB issued Accounting Standards Update (ASU) No. 2014-09, "Revenue from Contracts with Customers" (ASU No. 2014-09), which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers. This ASU supersedes the revenue recognition requirements in FASB ASC Topic 605, "Revenue Recognition," and most industry-specific guidance. This ASU sets forth a five-step model for determining when and how revenue is recognized. Under the model, an entity will be required to recognize revenue to depict the transfer of goods or services to a customer at an amount reflecting the consideration it expects to receive in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts.

In August 2015, the FASB issued ASU No. 2015-14, "Deferral of the Effective Date," which defers the effective date of ASU No. 2014-09. The ASU is now effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for interim and annual periods beginning after December 15, 2016. Entities may choose to adopt the standard using either a full retrospective approach or a modified retrospective approach.

ASU No. 2014-09 was amended in March 2016 by the provisions of ASU No. 2016-08, "Principal versus Agent Considerations (Reporting Revenue Gross versus Net)," in April 2016 by the provisions of ASU No. 2016-10, "Identifying Performance Obligations and Licensing," in May 2016 by the provisions of ASU No. 2016-12, "Narrow-Scope Improvements and Practical Expedients," and in December 2016 by the provisions of ASU No. 2016-20, "Technical Corrections and Improvements to Topic 606, Revenue From Contracts With Customers."

We will adopt the provisions of ASU No. 2014-09, as amended, with effect from January 1, 2018, and have elected not to early adopt the standard. We will adopt the new standard using the modified retrospective approach which we will apply only to contracts within the scope of the standard that are not complete at the date of initial application. Under this approach, we will apply the guidance retrospectively only to the most current period presented in the financial statements. The impact to our financial statements is immaterial but will include a cumulative effect reduction of $220 million to retained earnings from initially applying the new revenue standard relating to licensing revenues previously recognized. Under the new revenue standard licensing revenue will be recognized when the customer can utilize and benefit from their right to use the license.

In January 2016, the FASB issued ASU No. 2016-01, “Recognition and Measurement of Financial Assets and Financial Liabilities” (ASU No. 2016-01), to meet its objective of providing more decision-useful information about financial instruments. The ASU, among other things, requires entities to record the changes in fair value of equity investments, other than investments accounted for using the equity method, within net income. Under this ASU, entities will no longer be able to recognize unrealized holding gains and losses on available-for-sale securities in other comprehensive income. The ASU also requires additional disclosures relating to fair value measurement categories for financial assets and liabilities and eliminates certain disclosure requirements related to financial instruments measured at amortized cost. ASU No. 2016-01 is effective for interim and annual periods beginning after December 15, 2017, and the ASU should be adopted using a cumulative-effect adjustment to retained earnings as of the date of adoption.

Upon adoption of the standard, we will make a cumulative-effect adjustment to reclassify the accumulated unrealized holding gains and losses of $58 million related to our investment in Cenovus Energy from other comprehensive income to retained earnings. From January 1, 2018, we will begin reporting the changes in the fair value of our investment within net income. For additional information on our investment in Cenovus Energy, see Note 6—Investment in Cenovus Energy, Note 14—Fair Value Measurement, and Note 19—Accumulated Other Comprehensive Loss.

In February 2016, the FASB issued ASU No. 2016-02, “Leases” (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB ASC Topic 840, “Leases,” and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements. In January 2018, ASU No. 2016-02 was amended by the provisions of ASU No. 2018-01, “Land Easement Practical Expedient for Transition to Topic 842.” We plan to adopt ASU No. 2016-02, as amended, effective January 1, 2019, and continue to evaluate the ASU to determine the impact of adoption on our consolidated financial statements and disclosures, accounting policies and systems, business processes, and internal controls. We also continue to monitor proposals issued by the FASB to clarify the ASU and certain industry implementation issues. While our evaluation of ASU No. 2016-02 and related implementation activities are ongoing, we expect the adoption of the ASU to have a material impact on our consolidated financial statements and disclosures.

In June 2016, the FASB issued ASU No. 2016-13, “Measurement of Credit Losses on Financial Instruments” (ASU No. 2016-13), which sets forth the current expected credit loss model, a new forward-looking impairment model for certain financial instruments based on expected losses rather than incurred losses. The ASU is effective for interim and annual periods beginning after December 15, 2019, and early adoption of the standard is permitted. Entities are required to adopt ASU No. 2016-13 using a modified retrospective approach, subject to certain limited exceptions. We are currently evaluating the impact of the adoption of this ASU.

**Oil and Gas Operations** (Unaudited)

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, "Extractive Activities—Oil and Gas," and regulations of the U.S. Securities and Exchange Commission (SEC), we are making certain supplemental disclosures about our oil and gas exploration and production operations.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates' oil and gas activities in our operating segments. As a result, amounts reported as equity affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report.

As required by current authoritative guidelines, the estimated future date when an asset will be permanently shut down for economic reasons is based on historical 12-month first-of-month average prices and current costs. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Generally, our proved reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to production sharing contracts (PSCs), which are reported under the "economic interest" method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices, recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. At December 31, 2017, approximately 8 percent of our total proved reserves were under PSCs, located in our Asia Pacific/Middle East geographic reporting area, and 5 percent of our total proved reserves were under a variable-royalty regime, located in our Canada geographic reporting area.

Our reserves disclosures by geographic area include the United States, Canada, Europe (Norway and the United Kingdom), Asia Pacific/Middle East, Africa and Other Areas. Other Areas primarily consists of Russia, which we exited in 2015.

**Reserves Governance**

The recording and reporting of proved reserves are governed by criteria established by regulations of the SEC and FASB. Proved reserves are 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain it will commence the project within a reasonable time.

Proved reserves are further classified as either developed or undeveloped. Proved developed reserves are proved reserves that 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, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved reserves expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

We have a companywide, comprehensive, SEC-compliant internal policy that governs the determination and reporting of proved reserves. This policy is applied by the geoscientists and reservoir engineers in our business units around the world. As part of our internal control process, each business unit's reserves processes and controls are reviewed annually by an internal team which is headed by the company's Manager of Reserves Compliance and Reporting. This team, composed of internal reservoir engineers, geoscientists, finance personnel and a senior representative from DeGolyer and MacNaughton (D&M), a third-party petroleum engineering consulting firm, reviews the business units' reserves for adherence to SEC guidelines and company policy through on-site visits, teleconferences and review of documentation. In addition to providing independent reviews, this internal team also ensures reserves are calculated using consistent and appropriate standards and procedures. This team is independent of business unit line management and is responsible for reporting its findings to senior management. The team is responsible for communicating our reserves policy and procedures and is available for internal peer reviews and consultation on major projects or technical issues throughout the year. All of our proved reserves held by consolidated companies and our share of equity affiliates have been estimated by ConocoPhillips.

During 2017, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2017, were reviewed by D&M. The purpose of their review was to assess whether the adequacy and effectiveness of our internal processes and controls used to determine estimates of proved reserves are in accordance with SEC regulations. In such review, ConocoPhillips' technical staff presented D&M with an overview of the reserves data, as well as the methods and assumptions used in estimating reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures and relevant economic criteria. Management's intent in retaining D&M to review its processes and controls was to provide objective third-party input on these processes and controls. D&M's opinion was the general processes and controls employed by ConocoPhillips in estimating its December 31, 2017, proved reserves for the properties reviewed are in accordance with the SEC reserves definitions. D&M's report is included as Exhibit 99 of this Annual Report on Form 10-K.

The technical person primarily responsible for overseeing the processes and internal controls used in the preparation of the company's reserves estimates is the Manager of Reserves Compliance and Reporting. This individual holds a master's degree in petroleum engineering. He is a member of the Society of Petroleum Engineers with over 25 years of oil and gas industry experience and has held positions of increasing responsibility in reservoir engineering, subsurface and asset management in the United States and several international field locations.

Engineering estimates of the quantities of proved reserves are inherently imprecise. See the "Critical Accounting Estimates" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional discussion of the sensitivities surrounding these estimates.

**Proved Reserves**

| Years Ended December 31 | Crude Oil Millions of Barrels | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed and Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2014 | 1,063 | 676 | 1,739 | 24 | 411 | 227 | 204 | - | 2,605 |
| Revisions | (115) | (69) | (184) | - | (21) | (29) | - | - | (234) |
| Improved recovery | 4 | 4 | 8 | 1 | - | 31 | - | - | 40 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 20 | 57 | 77 | 1 | - | 7 | - | - | 85 |
| Production | (57) | (78) | (135) | (4) | (44) | (33) | - | - | (216) |
| Sales | - | (2) | (2) | (8) | - | - | - | - | (10) |
| End of 2015 | 915 | 588 | 1,503 | 14 | 346 | 203 | 204 | - | 2,270 |
| Revisions | (57) | (93) | (150) | 3 | - | 6 | - | - | (141) |
| Improved recovery | 6 | 3 | 9 | - | - | 7 | - | - | 16 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 33 | 79 | 112 | - | - | 7 | - | - | 119 |
| Production | (60) | (71) | (131) | (3) | (43) | (35) | (1) | - | (213) |
| Sales | - | - | - | (1) | - | (3) | - | - | (4) |
| End of 2016 | 837 | 506 | 1,343 | 13 | 303 | 185 | 203 | - | 2,047 |
| Revisions | 113 | 65 | 178 | 1 | 38 | 32 | - | - | 249 |
| Improved recovery | 6 | - | 6 | - | - | - | - | - | 6 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 41 | 210 | 251 | - | - | 2 | - | - | 253 |
| Production | (60) | (64) | (124) | (1) | (45) | (34) | (7) | - | (211) |
| Sales | - | (10) | (10) | (12) | - | - | - | - | (22) |
| **End of 2017** | 937 | 707 | 1,644 | 1 | 296 | 185 | 196 | - | 2,322 |
| *Equity affiliates* | | | | | | | | | |
| End of 2014 | - | - | - | - | - | 98 | - | 5 | 103 |
| Revisions | - | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (5) | - | (1) | (6) |
| Sales | - | - | - | - | - | - | - | (4) | (4) |
| End of 2015 | - | - | - | - | - | 93 | - | - | 93 |
| Revisions | - | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (5) | - | - | (5) |
| Sales | - | - | - | - | - | - | - | - | - |
| End of 2016 | - | - | - | - | - | 88 | - | - | 88 |
| Revisions | - | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (5) | - | - | (5) |
| Sales | - | - | - | - | - | - | - | - | - |
| **End of 2017** | - | - | - | - | - | 83 | - | - | 83 |
| *Total company* | | | | | | | | | |
| End of 2014 | 1,063 | 676 | 1,739 | 24 | 411 | 325 | 204 | 5 | 2,708 |
| End of 2015 | 915 | 588 | 1,503 | 14 | 346 | 296 | 204 | - | 2,363 |
| End of 2016 | 837 | 506 | 1,343 | 13 | 303 | 273 | 203 | - | 2,135 |
| **End of 2017** | 937 | 707 | 1,644 | 1 | 296 | 268 | 196 | - | 2,405 |

| Years Ended December 31 | Crude Oil | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2014 | 950 | 313 | 1,263 | 23 | 237 | 142 | 199 | - | 1,864 |
| End of 2015 | 819 | 283 | 1,102 | 13 | 200 | 139 | 204 | - | 1,658 |
| End of 2016 | 747 | 256 | 1,003 | 13 | 184 | 106 | 203 | - | 1,509 |
| **End of 2017** | 828 | 315 | 1,143 | 1 | 190 | 121 | 196 | - | 1,651 |
| *Equity affiliates* | | | | | | | | | |
| End of 2014 | - | - | - | - | - | 98 | - | 5 | 103 |
| End of 2015 | - | - | - | - | - | 93 | - | - | 93 |
| End of 2016 | - | - | - | - | - | 88 | - | - | 88 |
| **End of 2017** | - | - | - | - | - | 83 | - | - | 83 |
| **Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2014 | 113 | 363 | 476 | 1 | 174 | 85 | 5 | - | 741 |
| End of 2015 | 96 | 305 | 401 | 1 | 146 | 64 | - | - | 612 |
| End of 2016 | 90 | 250 | 340 | - | 119 | 79 | - | - | 538 |
| **End of 2017** | 109 | 392 | 501 | - | 106 | 64 | - | - | 671 |
| *Equity affiliates* | | | | | | | | | |
| End of 2014 | - | - | - | - | - | - | - | - | - |
| End of 2015 | - | - | - | - | - | - | - | - | - |
| End of 2016 | - | - | - | - | - | - | - | - | - |
| **End of 2017** | - | - | - | - | - | - | - | - | - |

Notable changes in proved crude oil reserves in the three years ended December 31, 2017, included:

- *Revisions*: In 2017, revisions in Alaska, Lower 48, Europe and Asia Pacific/Middle East were primarily due to higher prices. In 2016, revisions in Lower 48 and Alaska were primarily due to lower prices. In 2015, revisions in Alaska, Lower 48 and Asia Pacific/Middle East were primarily due to lower prices.

- *Extensions and discoveries*: In 2017, extensions and discoveries in Lower 48 were primarily due to continued drilling success in the Permian Unconventional, Eagle Ford and Bakken. In 2016, extensions and discoveries in Alaska were primarily due to drilling success in the Western North Slope, and extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford and Bakken.

- *Sales*: In 2017, Canada sales were due to the disposition of a majority of our western Canada assets.

| Years Ended December 31 | Natural Gas Liquids | | | | | | |
|---|---|---|---|---|---|---|---|
| | Millions of Barrels | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Total |
| **Developed and Undeveloped** | | | | | | | |
| *Consolidated operations* | | | | | | | |
| End of 2014 | 120 | 440 | 560 | 65 | 24 | 13 | 662 |
| Revisions | (1) | (84) | (85) | (10) | (1) | (2) | (98) |
| Improved recovery | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - |
| Extensions and discoveries | - | 10 | 10 | 2 | - | - | 12 |
| Production | (5) | (36) | (41) | (9) | (3) | (3) | (56) |
| Sales | - | (9) | (9) | (3) | - | - | (12) |
| End of 2015 | 114 | 321 | 435 | 45 | 20 | 8 | 508 |
| Revisions | (3) | (29) | (32) | 9 | 2 | - | (21) |
| Improved recovery | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - |
| Extensions and discoveries | - | 18 | 18 | 2 | - | - | 20 |
| Production | (4) | (32) | (36) | (8) | (3) | (3) | (50) |
| Sales | - | - | - | - | - | - | - |
| End of 2016 | 107 | 278 | 385 | 48 | 19 | 5 | 457 |
| Revisions | 4 | 29 | 33 | - | 2 | 1 | 36 |
| Improved recovery | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - |
| Extensions and discoveries | - | 71 | 71 | - | - | 1 | 72 |
| Production | (5) | (24) | (29) | (3) | (3) | (2) | (37) |
| Sales | - | (130) | (130) | (44) | - | - | (174) |
| **End of 2017** | 106 | 224 | 330 | 1 | 18 | 5 | 354 |
| | | | | | | | |
| *Equity affiliates* | | | | | | | |
| End of 2014 | - | - | - | - | - | 53 | 53 |
| Revisions | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (3) | (3) |
| Sales | - | - | - | - | - | - | - |
| End of 2015 | - | - | - | - | - | 50 | 50 |
| Revisions | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (3) | (3) |
| Sales | - | - | - | - | - | - | - |
| End of 2016 | - | - | - | - | - | 47 | 47 |
| Revisions | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (2) | (2) |
| Sales | - | - | - | - | - | - | - |
| **End of 2017** | - | - | - | - | - | 45 | 45 |
| | | | | | | | |
| *Total company* | | | | | | | |
| End of 2014 | 120 | 440 | 560 | 65 | 24 | 66 | 715 |
| End of 2015 | 114 | 321 | 435 | 45 | 20 | 58 | 558 |
| End of 2016 | 107 | 278 | 385 | 48 | 19 | 52 | 504 |
| **End of 2017** | 106 | 224 | 330 | 1 | 18 | 50 | 399 |

| Years Ended December 31 | Natural Gas Liquids | | | | | | |
|---|---|---|---|---|---|---|---|
| | Millions of Barrels | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Total |
| **Developed** | | | | | | | |
| *Consolidated operations* | | | | | | | |
| End of 2014 | 120 | 337 | 457 | 57 | 18 | 11 | 543 |
| End of 2015 | 114 | 235 | 349 | 45 | 16 | 8 | 418 |
| End of 2016 | 107 | 209 | 316 | 47 | 15 | 5 | 383 |
| **End of 2017** | 106 | 101 | 207 | 1 | 16 | 2 | 226 |
| *Equity affiliates* | | | | | | | |
| End of 2014 | - | - | - | - | - | 53 | 53 |
| End of 2015 | - | - | - | - | - | 50 | 50 |
| End of 2016 | - | - | - | - | - | 47 | 47 |
| **End of 2017** | - | - | - | - | - | 45 | 45 |
| **Undeveloped** | | | | | | | |
| *Consolidated operations* | | | | | | | |
| End of 2014 | - | 103 | 103 | 8 | 6 | 2 | 119 |
| End of 2015 | - | 86 | 86 | - | 4 | - | 90 |
| End of 2016 | - | 69 | 69 | 1 | 4 | - | 74 |
| **End of 2017** | - | 123 | 123 | - | 2 | 3 | 128 |
| *Equity affiliates* | | | | | | | |
| End of 2014 | - | - | - | - | - | - | - |
| End of 2015 | - | - | - | - | - | - | - |
| End of 2016 | - | - | - | - | - | - | - |
| **End of 2017** | - | - | - | - | - | - | - |

Notable changes in proved natural gas liquids reserves in the three years ended December 31, 2017, included:

- *Revisions*: In 2017, revisions in Lower 48 were primarily due to higher prices. In 2015, revisions in Lower 48 and Canada were primarily due to lower prices.

- *Extensions and discoveries*: In 2017, extensions and discoveries in Lower 48 were primarily due to continued drilling success in the Permian Unconventional, Eagle Ford and Bakken.

- *Sales*: In 2017, Lower 48 sales were due to the disposition of our interests in the San Juan Basin and Panhandle assets, while Canada sales were due to the disposition of a majority of our western Canada assets.

| Years Ended December 31 | Natural Gas | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Billions of Cubic Feet | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
| **Developed and Undeveloped** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| End of 2014 | 2,719 | 6,945 | 9,664 | 1,916 | 1,573 | 1,878 | 227 | 15,258 |
| Revisions | (293) | (884) | (1,177) | (111) | (27) | 110 | - | (1,205) |
| Improved recovery | - | - | - | 1 | - | 8 | - | 9 |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 4 | 103 | 107 | 44 | - | 2 | - | 153 |
| Production | (83) | (588) | (671) | (261) | (187) | (285) | - | (1,404) |
| Sales | - | (405) | (405) | (482) | - | - | - | (887) |
| End of 2015 | 2,347 | 5,171 | 7,518 | 1,107 | 1,359 | 1,713 | 227 | 11,924 |
| Revisions | (105) | (124) | (229) | 111 | 56 | 18 | - | (44) |
| Improved recovery | - | - | - | - | - | 1 | - | 1 |
| Purchases | - | - | - | 1 | - | - | - | 1 |
| Extensions and discoveries | 2 | 162 | 164 | 43 | - | 124 | - | 331 |
| Production | (73) | (494) | (567) | (192) | (177) | (288) | - | (1,224) |
| Sales | (69) | (1) | (70) | (33) | - | (42) | - | (145) |
| End of 2016 | 2,102 | 4,714 | 6,816 | 1,037 | 1,238 | 1,526 | 227 | 10,844 |
| Revisions | 287 | 460 | 747 | 8 | 167 | 16 | - | 938 |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 2 | 582 | 584 | 3 | - | 23 | - | 610 |
| Production | (71) | (338) | (409) | (71) | (188) | (267) | (3) | (938) |
| Sales | - | (2,885) | (2,885) | (966) | - | - | - | (3,851) |
| **End of 2017** | 2,320 | 2,533 | 4,853 | 11 | 1,217 | 1,298 | 224 | 7,603 |
| | | | | | | | | |
| *Equity affiliates* | | | | | | | | |
| End of 2014 | - | - | - | - | - | 5,242 | - | 5,242 |
| Revisions | - | - | - | - | - | (2) | - | (2) |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 268 | - | 268 |
| Production | - | - | - | - | - | (239) | - | (239) |
| Sales | - | - | - | - | - | - | - | - |
| End of 2015 | - | - | - | - | - | 5,269 | - | 5,269 |
| Revisions | - | - | - | - | - | (676) | - | (676) |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 125 | - | 125 |
| Production | - | - | - | - | - | (337) | - | (337) |
| Sales | - | - | - | - | - | - | - | - |
| End of 2016 | - | - | - | - | - | 4,381 | - | 4,381 |
| Revisions | - | - | - | - | - | 111 | - | 111 |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 185 | - | 185 |
| Production | - | - | - | - | - | (374) | - | (374) |
| Sales | - | - | - | - | - | - | - | - |
| **End of 2017** | - | - | - | - | - | 4,303 | - | 4,303 |
| | | | | | | | | |
| *Total company* | | | | | | | | |
| End of 2014 | 2,719 | 6,945 | 9,664 | 1,916 | 1,573 | 7,120 | 227 | 20,500 |
| End of 2015 | 2,347 | 5,171 | 7,518 | 1,107 | 1,359 | 6,982 | 227 | 17,193 |
| End of 2016 | 2,102 | 4,714 | 6,816 | 1,037 | 1,238 | 5,907 | 227 | 15,225 |
| **End of 2017** | 2,320 | 2,533 | 4,853 | 11 | 1,217 | 5,601 | 224 | 11,906 |

| Years Ended December 31 | Natural Gas | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Billions of Cubic Feet | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
| **Developed** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| End of 2014 | 2,663 | 5,922 | 8,585 | 1,801 | 1,182 | 1,553 | 226 | 13,347 |
| End of 2015 | 2,313 | 4,458 | 6,771 | 1,101 | 1,088 | 1,421 | 227 | 10,608 |
| End of 2016 | 2,094 | 4,199 | 6,293 | 1,031 | 998 | 1,188 | 227 | 9,737 |
| **End of 2017** | 2,310 | 1,597 | 3,907 | 11 | 997 | 945 | 224 | 6,084 |
| *Equity affiliates* | | | | | | | | |
| End of 2014 | - | - | - | - | - | 3,954 | - | 3,954 |
| End of 2015 | - | - | - | - | - | 4,482 | - | 4,482 |
| End of 2016 | - | - | - | - | - | 4,110 | - | 4,110 |
| **End of 2017** | - | - | - | - | - | 4,044 | - | 4,044 |
| **Undeveloped** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| End of 2014 | 56 | 1,023 | 1,079 | 115 | 391 | 325 | 1 | 1,911 |
| End of 2015 | 34 | 713 | 747 | 6 | 271 | 292 | - | 1,316 |
| End of 2016 | 8 | 515 | 523 | 6 | 240 | 338 | - | 1,107 |
| **End of 2017** | 10 | 936 | 946 | - | 220 | 353 | - | 1,519 |
| *Equity affiliates* | | | | | | | | |
| End of 2014 | - | - | - | - | - | 1,288 | - | 1,288 |
| End of 2015 | - | - | - | - | - | 787 | - | 787 |
| End of 2016 | - | - | - | - | - | 271 | - | 271 |
| **End of 2017** | - | - | - | - | - | 259 | - | 259 |

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed in production operations.

Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Notable changes in proved natural gas reserves in the three years ended December 31, 2017, included:

- *Revisions*: In 2017, revisions in Alaska, Lower 48 and Europe were primarily due to higher prices. In 2016, revisions in our equity affiliates in Asia Pacific/Middle East were primarily due to lower prices. In 2015, revisions in Lower 48, Alaska and Canada were primarily due to lower prices, partially offset by positive revisions in Asia Pacific/Middle East from Indonesia.

- *Extensions and discoveries*: In 2017, extensions and discoveries in Lower 48 were primarily due to continued drilling success in the Permian Unconventional, Eagle Ford and Bakken. In 2015, for our equity affiliates in Asia Pacific/Middle East, extensions and discoveries were due to APLNG's ongoing development drilling onshore Australia.

- *Sales*: In 2017, Lower 48 sales were due to the disposition of our interests in the San Juan Basin and Panhandle assets, while Canada sales were due to the disposition of a majority of our western Canada assets. In 2015, Lower 48 sales were due to the disposition of noncore assets in South Texas, East Texas and North Louisiana and sales of assets in British Columbia, Saskatchewan and Alberta impacted Canada.

| Years Ended December 31 | Bitumen Millions of Barrels Canada |
|---|---|
| **Developed and Undeveloped** | |
| *Consolidated operations* | |
| End of 2014 | 598 |
| Revisions | 94 |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | - |
| Production | (5) |
| Sales | - |
| End of 2015 | 687 |
| Revisions | (515) |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | - |
| Production | (13) |
| Sales | - |
| End of 2016 | 159 |
| Revisions | 16 |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 96 |
| Production | (21) |
| Sales | - |
| **End of 2017** | 250 |
| | |
| *Equity affiliates* | |
| End of 2014 | 1,468 |
| Revisions | 190 |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 99 |
| Production | (51) |
| Sales | - |
| End of 2015 | 1,706 |
| Revisions | (573) |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 10 |
| Production | (54) |
| Sales | - |
| End of 2016 | 1,089 |
| Revisions | - |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | - |
| Production | (23) |
| Sales | (1,066) |
| **End of 2017** | - |
| | |
| *Total company* | |
| End of 2014 | 2,066 |
| End of 2015 | 2,393 |
| End of 2016 | 1,248 |
| **End of 2017** | 250 |

| Years Ended December 31 | Bitumen |
|---|---|
| | Millions of Barrels |
| | Canada |
| **Developed** | |
| *Consolidated operations* | |
| End of 2014 | 13 |
| End of 2015 | 111 |
| End of 2016 | 159 |
| **End of 2017** | 154 |
| | |
| *Equity affiliates* | |
| End of 2014 | 187 |
| End of 2015 | 311 |
| End of 2016 | 322 |
| **End of 2017** | - |
| | |
| **Undeveloped** | |
| *Consolidated operations* | |
| End of 2014 | 585 |
| End of 2015 | 576 |
| End of 2016 | - |
| **End of 2017** | 96 |
| | |
| *Equity affiliates* | |
| End of 2014 | 1,281 |
| End of 2015 | 1,395 |
| End of 2016 | 767 |
| **End of 2017** | - |

Notable changes in proved bitumen reserves in the three years ended December 31, 2017, included:

- *Revisions*: In 2017, revisions were primarily due to higher prices at Surmont. In 2016, for both our consolidated operations and equity affiliates revisions were primarily related to lower prices which resulted in reserve reductions at Surmont, Foster Creek, Christina Lake and Narrows Lake. In 2015, for both our consolidated operations and equity affiliates revisions were primarily related to reduced royalties from lower prices at Surmont, Foster Creek, Christina Lake and Narrows Lake.

- *Extensions and discoveries*: In 2017, extensions and discoveries were primarily due to higher prices at Surmont, which allowed undeveloped reserves previously de-booked due to low prices to be recognized. In 2015, for our equity affiliates extensions and discoveries were related to approval of development at Christina Lake.

- *Sales*: In 2017, sales were due to the disposition of our 50 percent interest in the FCCL Partnership.

| Years Ended December 31 | Total Proved Reserves | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels of Oil Equivalent | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed and Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2014 | 1,636 | 2,274 | 3,910 | 1,006 | 697 | 553 | 242 | - | 6,408 |
| Revisions | (165) | (301) | (466) | 66 | (26) | (12) | - | - | (438) |
| Improved recovery | 4 | 4 | 8 | 2 | - | 32 | - | - | 42 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 20 | 84 | 104 | 10 | - | 8 | - | - | 122 |
| Production | (75) | (211) | (286) | (62) | (78) | (84) | - | - | (510) |
| Sales | - | (79) | (79) | (92) | - | - | - | - | (171) |
| End of 2015 | 1,420 | 1,771 | 3,191 | 930 | 593 | 497 | 242 | - | 5,453 |
| Revisions | (77) | (143) | (220) | (484) | 11 | 9 | - | - | (684) |
| Improved recovery | 6 | 3 | 9 | - | - | 7 | - | - | 16 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 33 | 124 | 157 | 9 | - | 28 | - | - | 194 |
| Production | (76) | (185) | (261) | (55) | (76) | (87) | (1) | - | (480) |
| Sales | (12) | - | (12) | (7) | - | (10) | - | - | (29) |
| End of 2016 | 1,294 | 1,570 | 2,864 | 393 | 528 | 444 | 241 | - | 4,470 |
| Revisions | 166 | 170 | 336 | 18 | 68 | 36 | - | - | 458 |
| Improved recovery | 6 | - | 6 | - | - | - | - | - | 6 |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | 41 | 378 | 419 | 97 | - | 7 | - | - | 523 |
| Production | (77) | (144) | (221) | (37) | (79) | (81) | (8) | - | (426) |
| Sales | - | (621) | (621) | (217) | - | - | - | - | (838) |
| **End of 2017** | 1,430 | 1,353 | 2,783 | 254 | 517 | 406 | 233 | - | 4,193 |
| *Equity affiliates* | | | | | | | | | |
| End of 2014 | - | - | - | 1,468 | - | 1,025 | - | 5 | 2,498 |
| Revisions | - | - | - | 190 | - | (1) | - | - | 189 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | 99 | - | 45 | - | - | 144 |
| Production | - | - | - | (51) | - | (48) | - | (1) | (100) |
| Sales | - | - | - | - | - | - | - | (4) | (4) |
| End of 2015 | - | - | - | 1,706 | - | 1,021 | - | - | 2,727 |
| Revisions | - | - | - | (573) | - | (113) | - | - | (686) |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | 10 | - | 21 | - | - | 31 |
| Production | - | - | - | (54) | - | (64) | - | - | (118) |
| Sales | - | - | - | - | - | - | - | - | - |
| End of 2016 | - | - | - | 1,089 | - | 865 | - | - | 1,954 |
| Revisions | - | - | - | - | - | 18 | - | - | 18 |
| Improved recovery | - | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 31 | - | - | 31 |
| Production | - | - | - | (23) | - | (69) | - | - | (92) |
| Sales | - | - | - | (1,066) | - | - | - | - | (1,066) |
| **End of 2017** | - | - | - | - | - | 845 | - | - | 845 |
| *Total company* | | | | | | | | | |
| End of 2014 | 1,636 | 2,274 | 3,910 | 2,474 | 697 | 1,578 | 242 | 5 | 8,906 |
| End of 2015 | 1,420 | 1,771 | 3,191 | 2,636 | 593 | 1,518 | 242 | - | 8,180 |
| End of 2016 | 1,294 | 1,570 | 2,864 | 1,482 | 528 | 1,309 | 241 | - | 6,424 |
| **End of 2017** | 1,430 | 1,353 | 2,783 | 254 | 517 | 1,251 | 233 | - | 5,038 |

| Years Ended December 31 | Total Proved Reserves | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Millions of Barrels of Oil Equivalent | | | | | | | | |
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **Developed** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2014 | 1,514 | 1,637 | 3,151 | 393 | 452 | 412 | 237 | - | 4,645 |
| End of 2015 | 1,318 | 1,261 | 2,579 | 352 | 398 | 384 | 242 | - | 3,955 |
| End of 2016 | 1,203 | 1,165 | 2,368 | 391 | 365 | 309 | 241 | - | 3,674 |
| **End of 2017** | 1,319 | 682 | 2,001 | 158 | 372 | 281 | 233 | - | 3,045 |
| *Equity affiliates* | | | | | | | | | |
| End of 2014 | - | - | - | 187 | - | 810 | - | 5 | 1,002 |
| End of 2015 | - | - | - | 311 | - | 890 | - | - | 1,201 |
| End of 2016 | - | - | - | 322 | - | 820 | - | - | 1,142 |
| **End of 2017** | - | - | - | - | - | 802 | - | - | 802 |
| **Undeveloped** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| End of 2014 | 122 | 637 | 759 | 613 | 245 | 141 | 5 | - | 1,763 |
| End of 2015 | 102 | 510 | 612 | 578 | 195 | 113 | - | - | 1,498 |
| End of 2016 | 91 | 405 | 496 | 2 | 163 | 135 | - | - | 796 |
| **End of 2017** | 111 | 671 | 782 | 96 | 145 | 125 | - | - | 1,148 |
| *Equity affiliates* | | | | | | | | | |
| End of 2014 | - | - | - | 1,281 | - | 215 | - | - | 1,496 |
| End of 2015 | - | - | - | 1,395 | - | 131 | - | - | 1,526 |
| End of 2016 | - | - | - | 767 | - | 45 | - | - | 812 |
| **End of 2017** | - | - | - | - | - | 43 | - | - | 43 |

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE.

**Proved Undeveloped Reserves**

We had 1,191 million BOE of proved undeveloped reserves at year-end 2017, compared with 1,608 million BOE at year-end 2016. The following table shows changes in total proved undeveloped reserves for 2017:

| | **Proved Undeveloped Reserves** Millions of Barrels of Oil Equivalent |
|---|---|
| End of 2016 | 1,608 |
| Transfers to proved developed | (194) |
| Revisions | 29 |
| Improved recovery | 6 |
| Purchases | - |
| Extensions and discoveries | 527 |
| Sales | (785) |
| **End of 2017** | 1,191 |

Sales were primarily due to the disposition of our 50 percent interest in the FCCL Partnership, which were partially offset by extensions and discoveries primarily in the Lower 48, Alaska, Canada and Asia Pacific/Middle East.

As a result, at December 31, 2017, our proved undeveloped reserves represented 24 percent of total proved reserves, compared with 25 percent at December 31, 2016. Costs incurred for the year ended December 31, 2017, relating to the development of proved undeveloped reserves were $3.5 billion. A portion of our costs incurred each year relates to development projects where the proved undeveloped reserves will be converted to proved developed reserves in future years.

At the end of 2017, more than 90 percent of total proved undeveloped reserves are currently under development or scheduled for development within five years of initial disclosure. The remainder are to be developed as parts of major projects ongoing in our Europe and Asia Pacific/Middle East regions. All major development areas are currently producing and are expected to have proved undeveloped reserves convert to proved developed over time. Approximately 74 percent of our total proved undeveloped reserves at year-end 2017 are in North America, and all of these reserve volumes are planned for development within five years of initial disclosure.

**Results of Operations**

The company's results of operations from oil and gas activities for the years 2017, 2016 and 2015 are shown in the following tables. Non-oil and gas activities, such as pipeline and marine operations, liquefied natural gas operations, crude oil and gas marketing activities, and the profit element of transportation operations in which we have an ownership interest are excluded. Additional information about selected line items within the results of operations tables is shown below:

- Sales include sales to unaffiliated entities attributable primarily to the company's net working interests and royalty interests. Sales are net of fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are not consolidated.

- Transportation costs reflect fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are consolidated.

- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.

- Production costs include costs incurred to operate and maintain wells, related equipment and facilities used in the production of petroleum liquids and natural gas.

- Taxes other than income taxes include production, property and other non-income taxes.

- Depreciation of support equipment is reclassified as applicable.

- Other related expenses include inventory fluctuations, foreign currency transaction gains and losses and other miscellaneous expenses.

## Results of Operations

| Year Ended December 31, 2017 | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| *Consolidated operations* | | | | | | | | | |
| Sales | $ 3,542 | 4,557 | 8,099 | 705 | 3,527 | 2,752 | 487 | - | 15,570 |
| Transfers | 4 | - | 4 | - | - | 411 | - | - | 415 |
| Transportation costs | (706) | - | (706) | - | - | (80) | - | - | (786) |
| Other revenues | 14 | 28 | 42 | 2,158 | 68 | 11 | 48 | 322 | 2,649 |
| Total revenues | 2,854 | 4,585 | 7,439 | 2,863 | 3,595 | 3,094 | 535 | 322 | 17,848 |
| Production costs excluding taxes | 985 | 1,669 | 2,654 | 609 | 775 | 574 | 44 | - | 4,656 |
| Taxes other than income taxes | 275 | 318 | 593 | 33 | 32 | 39 | 2 | - | 699 |
| Exploration expenses | 83 | 584 | 667 | 22 | 45 | 97 | 61 | 45 | 937 |
| Depreciation, depletion and amortization | 730 | 2,685 | 3,415 | 438 | 1,234 | 1,283 | 16 | - | 6,386 |
| Impairments | 179 | 3,969 | 4,148 | 22 | 46 | - | - | - | 4,216 |
| Other related expenses | (7) | 62 | 55 | 7 | 57 | 60 | 6 | - | 185 |
| Accretion | 52 | 63 | 115 | 16 | 172 | 37 | - | - | 340 |
| | 557 | (4,765) | (4,208) | 1,716 | 1,234 | 1,004 | 406 | 277 | 429 |
| Income tax provision (benefit) | (678) | (2,424) | (3,102) | (651) | 702 | 363 | 428 | 11 | (2,249) |
| Results of operations | $ 1,235 | (2,341) | (1,106) | 2,367 | 532 | 641 | (22) | 266 | 2,678 |
| | | | | | | | | | |
| *Equity affiliates* | | | | | | | | | |
| Sales | $ - | - | - | 528 | - | 563 | - | - | 1,091 |
| Transfers | - | - | - | - | - | 1,398 | - | - | 1,398 |
| Transportation costs | - | - | - | - | - | - | - | - | - |
| Other revenues | - | - | - | 5 | - | - | - | - | 5 |
| Total revenues | - | - | - | 533 | - | 1,961 | - | - | 2,494 |
| Production costs excluding taxes | - | - | - | 174 | - | 363 | - | - | 537 |
| Taxes other than income taxes | - | - | - | 7 | - | 604 | - | - | 611 |
| Exploration expenses | - | - | - | 1 | - | 1,699 | - | - | 1,700 |
| Depreciation, depletion and amortization | - | - | - | 150 | - | 617 | - | - | 767 |
| Impairments | - | - | - | - | - | 1,717 | - | - | 1,717 |
| Other related expenses | - | - | - | 4 | - | 22 | - | 19 | 45 |
| Accretion | - | - | - | 2 | - | 11 | - | - | 13 |
| | - | - | - | 195 | - | (3,072) | - | (19) | (2,896) |
| Income tax provision (benefit) | - | - | - | 26 | - | (998) | - | 13 | (959) |
| Results of operations | $ - | - | - | 169 | - | (2,074) | - | (32) | (1,937) |

| Year Ended December 31, 2016 | | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| *Consolidated operations* | | | | | | | | | | |
| Sales | $ | 2,793 | 4,117 | 6,910 | 661 | 2,678 | 2,350 | - | - | 12,599 |
| Transfers | | 8 | - | 8 | - | - | 347 | - | - | 355 |
| Transportation costs | | (676) | - | (676) | - | - | (40) | - | - | (716) |
| Other revenues | | 375 | 111 | 486 | 48 | (34) | (25) | 147 | 9 | 631 |
| Total revenues | | 2,500 | 4,228 | 6,728 | 709 | 2,644 | 2,632 | 147 | 9 | 12,869 |
| Production costs excluding taxes | | 1,056 | 1,967 | 3,023 | 790 | 795 | 640 | 23 | (2) | 5,269 |
| Taxes other than income taxes | | 231 | 308 | 539 | 55 | 31 | 30 | 1 | - | 656 |
| Exploration expenses | | 45 | 1,227 | 1,272 | 332 | 90 | 38 | 138 | 41 | 1,911 |
| Depreciation, depletion and amortization | | 738 | 4,167 | 4,905 | 881 | 1,390 | 1,402 | 2 | - | 8,580 |
| Impairments | | 1 | 148 | 149 | 88 | (161) | 44 | - | - | 120 |
| Other related expenses | | 52 | 70 | 122 | (51) | (77) | (13) | 4 | 4 | (11) |
| Accretion | | 52 | 72 | 124 | 32 | 210 | 35 | - | - | 401 |
| | | 325 | (3,731) | (3,406) | (1,418) | 366 | 456 | (21) | (34) | (4,057) |
| Income tax provision (benefit) | | (29) | (1,349) | (1,378) | (406) | 3 | 250 | (72) | (13) | (1,616) |
| Results of operations | $ | 354 | (2,382) | (2,028) | (1,012) | 363 | 206 | 51 | (21) | (2,441) |
| *Equity affiliates* | | | | | | | | | | |
| Sales | $ | - | - | - | 860 | - | 449 | - | - | 1,309 |
| Transfers | | - | - | - | - | - | 825 | - | - | 825 |
| Transportation costs | | - | - | - | - | - | - | - | - | - |
| Other revenues | | - | - | - | - | - | (2) | - | - | (2) |
| Total revenues | | - | - | - | 860 | - | 1,272 | - | - | 2,132 |
| Production costs excluding taxes | | - | - | - | 431 | - | 256 | - | - | 687 |
| Taxes other than income taxes | | - | - | - | 15 | - | 476 | - | - | 491 |
| Exploration expenses | | - | - | - | 6 | - | - | - | - | 6 |
| Depreciation, depletion and amortization | | - | - | - | 309 | - | 548 | - | - | 857 |
| Impairments | | - | - | - | 9 | - | - | - | - | 9 |
| Other related expenses | | - | - | - | (7) | - | 8 | - | 24 | 25 |
| Accretion | | - | - | - | 8 | - | 7 | - | - | 15 |
| | | - | - | - | 89 | - | (23) | - | (24) | 42 |
| Income tax provision (benefit) | | - | - | - | 24 | - | (201) | - | - | (177) |
| Results of operations | $ | - | - | - | 65 | - | 178 | - | (24) | 219 |

| Year Ended December 31, 2015 | | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| *Consolidated operations* | | | | | | | | | | |
| Sales | $ | 3,206 | 4,992 | 8,198 | 930 | 3,637 | 2,741 | - | - | 15,506 |
| Transfers | | 15 | - | 15 | - | - | 629 | - | - | 644 |
| Transportation costs | | (599) | - | (599) | - | - | (40) | - | - | (639) |
| Other revenues | | (5) | 452 | 447 | (19) | (28) | 6 | 13 | 2 | 421 |
| Total revenues | | 2,617 | 5,444 | 8,061 | 911 | 3,609 | 3,336 | 13 | 2 | 15,932 |
| Production costs excluding taxes | | 1,242 | 2,420 | 3,662 | 923 | 1,137 | 815 | 42 | 1 | 6,580 |
| Taxes other than income taxes | | 281 | 358 | 639 | 62 | 35 | 33 | 3 | 1 | 773 |
| Exploration expenses | | 682 | 1,583 | 2,265 | 457 | 170 | 268 | 990 | 43 | 4,193 |
| Depreciation, depletion and amortization | | 548 | 4,192 | 4,740 | 777 | 1,813 | 1,321 | - | - | 8,651 |
| Impairments | | 8 | (2) | 6 | 3 | 724 | 3 | - | - | 736 |
| Other related expenses | | (30) | 78 | 48 | 8 | 9 | (2) | (8) | 5 | 60 |
| Accretion | | 52 | 83 | 135 | 49 | 240 | 34 | - | - | 458 |
| | | (166) | (3,268) | (3,434) | (1,368) | (519) | 864 | (1,014) | (48) | (5,519) |
| Income tax provision (benefit) | | (89) | (1,193) | (1,282) | (244) | (816) | 430 | (406) | (27) | (2,345) |
| Results of operations | $ | (77) | (2,075) | (2,152) | (1,124) | 297 | 434 | (608) | (21) | (3,174) |
| | | | | | | | | | | |
| *Equity affiliates* | | | | | | | | | | |
| Sales | $ | - | - | - | 917 | - | 536 | - | 50 | 1,503 |
| Transfers | | - | - | - | - | - | 950 | - | - | 950 |
| Transportation costs | | - | - | - | - | - | - | - | - | - |
| Other revenues | | - | - | - | 34 | - | 4 | - | 58 | 96 |
| Total revenues | | - | - | - | 951 | - | 1,490 | - | 108 | 2,549 |
| Production costs excluding taxes | | - | - | - | 474 | - | 248 | - | 13 | 735 |
| Taxes other than income taxes | | - | - | - | 15 | - | 723 | - | 13 | 751 |
| Exploration expenses | | - | - | - | 12 | - | 190 | - | - | 202 |
| Depreciation, depletion and amortization | | - | - | - | 367 | - | 197 | - | 5 | 569 |
| Impairments | | - | - | - | - | - | 1,396 | - | 3 | 1,399 |
| Other related expenses | | - | - | - | (2) | - | (13) | - | 23 | 8 |
| Accretion | | - | - | - | 7 | - | 10 | - | 1 | 18 |
| | | - | - | - | 78 | - | (1,261) | - | 50 | (1,133) |
| Income tax provision (benefit) | | - | - | - | 20 | - | (155) | - | 10 | (125) |
| Results of operations | $ | - | - | - | 58 | - | (1,106) | - | 40 | (1,008) |

**Statistics**

| **Net Production** | **2017** | 2016 | 2015 |
|---|---|---|---|
| | Thousands of Barrels Daily | | |
| **Crude Oil** | | | |
| *Consolidated operations* | | | |
| Alaska | **167** | 163 | 158 |
| Lower 48 | **180** | 195 | 206 |
| United States | **347** | 358 | 364 |
| Canada | **3** | 7 | 12 |
| Europe | **122** | 120 | 120 |
| Asia Pacific/Middle East | **93** | 97 | 91 |
| Africa | **20** | 2 | - |
| Total consolidated operations | **585** | 584 | 587 |
| *Equity affiliates* | | | |
| Asia Pacific/Middle East | **14** | 14 | 14 |
| Other areas | **-** | - | 4 |
| Total equity affiliates | **14** | 14 | 18 |
| Total company | **599** | **598** | **605** |
| **Natural Gas Liquids** | | | |
| *Consolidated operations* | | | |
| Alaska | **14** | 12 | 13 |
| Lower 48 | **69** | 88 | 94 |
| United States | **83** | 100 | 107 |
| Canada | **9** | 23 | 26 |
| Europe | **8** | 7 | 7 |
| Asia Pacific/Middle East | **4** | 7 | 9 |
| Total consolidated operations | **104** | 137 | 149 |
| *Equity affiliates*—Asia Pacific/Middle East | **7** | 8 | 7 |
| Total company | **111** | **145** | **156** |
| **Bitumen** | | | |
| *Consolidated operations*—Canada | **59** | 35 | 13 |
| *Equity affiliates*—Canada | **63** | 148 | 138 |
| Total company | **122** | 183 | 151 |
| **Natural Gas** | Millions of Cubic Feet Daily | | |
| *Consolidated operations* | | | |
| Alaska | **7** | 25 | 42 |
| Lower 48 | **898** | 1,219 | 1,472 |
| United States | **905** | 1,244 | 1,514 |
| Canada | **187** | 524 | 715 |
| Europe | **476** | 459 | 475 |
| Asia Pacific/Middle East | **687** | 730 | 717 |
| Africa | **8** | 1 | 1 |
| Total consolidated operations | **2,263** | 2,958 | 3,422 |
| *Equity affiliates*—Asia Pacific/Middle East | **1,007** | 899 | 638 |
| Total company | **3,270** | **3,857** | **4,060** |

| Average Sales Prices | | 2017 | 2016 | 2015 |
|---|---|---|---|---|
| **Crude Oil Per Barrel** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **42.69** | 31.68 | 41.84 |
| Lower 48 | | **47.36** | 37.49 | 42.62 |
| United States | | **45.01** | 34.70 | 42.27 |
| Canada | | **43.69** | 35.25 | 39.52 |
| Europe | | **54.04** | 43.66 | 52.75 |
| Asia Pacific/Middle East | | **54.38** | 42.23 | 49.70 |
| Africa | | **55.11** | - | 60.79 |
| Total international | | **54.16** | 42.76 | 50.79 |
| Total consolidated operations | | **48.70** | 37.67 | 45.48 |
| *Equity affiliates* | | | | |
| Asia Pacific/Middle East | | **54.76** | 44.11 | 53.12 |
| Other areas | | - | - | 37.21 |
| Total equity affiliates | | **54.76** | 44.11 | 49.92 |
| Total operations | | **48.84** | 37.82 | 45.61 |
| **Natural Gas Liquids Per Barrel** | | | | |
| *Consolidated operations* | | | | |
| Lower 48 | $ | **22.20** | 14.34 | 14.01 |
| United States | | **22.20** | 14.34 | 14.01 |
| Canada | | **21.51** | 14.82 | 17.02 |
| Europe | | **34.07** | 22.62 | 27.56 |
| Asia Pacific/Middle East | | **41.37** | 29.00 | 37.78 |
| Total international | | **30.34** | 19.06 | 23.21 |
| Total consolidated operations | | **24.21** | 15.72 | 16.83 |
| *Equity affiliates*—Asia Pacific/Middle East | | **38.74** | 31.13 | 35.79 |
| Total operations | | **25.22** | 16.68 | 17.79 |
| **Bitumen Per Barrel** | | | | |
| *Consolidated operations*—Canada | $ | **21.43** | 12.91 | 20.13 |
| *Equity affiliates*—Canada | | **23.83** | 15.80 | 18.58 |
| **Natural Gas Per Thousand Cubic Feet** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **2.72** | 5.22 | 4.33 |
| Lower 48 | | **2.73** | 2.20 | 2.43 |
| United States | | **2.73** | 2.24 | 2.47 |
| Canada | | **1.93** | 1.49 | 1.91 |
| Europe | | **5.72** | 4.71 | 7.14 |
| Asia Pacific/Middle East | | **4.66** | 4.15 | 6.08 |
| Africa | | **3.53** | - | - |
| Total international | | **4.64** | 3.49 | 4.78 |
| Total consolidated operations | | **3.87** | 2.97 | 3.77 |
| *Equity affiliates*—Asia Pacific/Middle East | | **4.27** | 2.97 | 4.83 |
| Total operations | | **4.00** | 2.97 | 3.93 |

*Average sales prices for Alaska crude oil and Asia Pacific/Middle East natural gas above reflect a reduction for transportation costs in which we have an ownership interest that are incurred subsequent to the terminal point of the production function. Accordingly, the average sales prices differ from those discussed in Item 7 of Management's Discussion and Analysis of Financial Condition and Results of Operations.*

| | | 2017 | 2016 | 2015 |
|---|---|---|---|---|
| **Average Production Costs Per Barrel of Oil Equivalent*** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **14.83** | 16.12 | 19.12 |
| Lower 48 | | **11.46** | 11.06 | 12.17 |
| United States | | **12.52** | 12.42 | 13.88 |
| Canada | | **16.36** | 14.20 | 14.88 |
| Europe | | **10.16** | 10.70 | 15.05 |
| Asia Pacific/Middle East | | **7.42** | 7.74 | 10.20 |
| Africa | | **5.74** | 31.42 | - |
| Total international | | **10.08** | 10.53 | 13.41 |
| Total consolidated operations | | **11.34** | 11.54 | 13.67 |
| *Equity affiliates* | | | | |
| Canada | | **7.57** | 7.96 | 9.41 |
| Asia Pacific/Middle East | | **5.26** | 4.04 | 5.31 |
| Other areas | | **-** | - | 8.90 |
| Total equity affiliates | | **5.84** | 5.85 | 7.46 |
| **Average Production Costs Per Barrel—Bitumen** | | | | |
| *Consolidated operations*—Canada | $ | **14.63** | 24.59 | 61.87 |
| *Equity affiliates*—Canada | | **18.74** | 7.96 | 9.41 |
| **Taxes Other Than Income Taxes Per Barrel of Oil Equivalent** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **4.14** | 3.53 | 4.33 |
| Lower 48 | | **2.18** | 1.73 | 1.80 |
| United States | | **2.80** | 2.21 | 2.42 |
| Canada | | **0.89** | 0.99 | 1.00 |
| Europe | | **0.42** | 0.42 | 0.46 |
| Asia Pacific/Middle East | | **0.50** | 0.36 | 0.41 |
| Africa | | **0.26** | 1.37 | - |
| Total international | | **0.53** | 0.55 | 0.62 |
| Total consolidated operations | | **1.70** | 1.44 | 1.61 |
| *Equity affiliates* | | | | |
| Canada | | **0.30** | 0.28 | 0.30 |
| Asia Pacific/Middle East | | **8.76** | 7.52 | 15.48 |
| Other areas | | **-** | - | 8.90 |
| Total equity affiliates | | **6.64** | 4.18 | 7.62 |
| **Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **10.99** | 11.26 | 8.43 |
| Lower 48 | | **18.44** | 23.43 | 21.07 |
| United States | | **16.10** | 20.15 | 17.96 |
| Canada | | **11.76** | 15.84 | 12.52 |
| Europe | | **16.18** | 18.71 | 24.00 |
| Asia Pacific/Middle East | | **16.58** | 16.95 | 16.53 |
| Africa | | **2.09** | 2.73 | - |
| Total international | | **14.96** | 17.22 | 17.98 |
| Total consolidated operations | | **15.55** | 18.78 | 17.97 |
| *Equity affiliates* | | | | |
| Canada | | **6.52** | 5.70 | 7.29 |
| Asia Pacific/Middle East | | **8.94** | 8.65 | 4.22 |
| Other areas | | **-** | - | 3.42 |
| Total equity affiliates | | **8.34** | 7.29 | 5.77 |

**Includes bitumen.*

## Development and Exploration Activities

The following two tables summarize our net interest in productive and dry exploratory and development wells in the years ended December 31, 2017, 2016 and 2015. A "development well" is a well drilled within the proved area of a reservoir to the depth of a stratigraphic horizon known to be productive. An "exploratory well" is a well drilled to find and produce crude oil or natural gas in an unknown field or a new reservoir within a proven field. Exploratory wells also include wells drilled in areas near or offsetting current production, or in areas where well density or production history have not achieved statistical certainty of results. Excluded from the exploratory well count are stratigraphic-type exploratory wells, primarily relating to oil sands delineation wells located in Canada and coalbed methane test wells located in Asia Pacific/Middle East.

| **Net Wells Completed** | Productive | | | Dry | | |
|---|---|---|---|---|---|---|
| | **2017** | 2016 | 2015 | **2017** | 2016 | 2015 |
| **Exploratory** | | | | | | |
| *Consolidated operations* | | | | | | |
| Alaska | **-** | 2 | - | **-** | 1 | - |
| Lower 48 | **13** | 8 | 47 | **3** | 1 | 4 |
| United States | **13** | 10 | 47 | **3** | 2 | 4 |
| Canada | **13** | 8 | 16 | **-** | 1 | 3 |
| Europe | ***** | * | * | ***** | 1 | * |
| Asia Pacific/Middle East | **1** | 1 | 1 | **1** | - | 2 |
| Africa | **-** | 1 | * | **-** | - | * |
| Other areas | **-** | - | - | **1** | - | - |
| Total consolidated operations | **27** | 20 | 64 | **5** | 4 | 9 |
| *Equity affiliates* | | | | | | |
| Asia Pacific/Middle East | **14** | 20 | 19 | **-** | - | * |
| Total equity affiliates | **14** | 20 | 19 | **-** | - | - |
| | | | | | | |
| **Development** | | | | | | |
| *Consolidated operations* | | | | | | |
| Alaska | **9** | 9 | 18 | **-** | - | - |
| Lower 48 | **161** | 119 | 347 | **-** | - | - |
| United States | **170** | 128 | 365 | **-** | - | - |
| Canada | **13** | 47 | 47 | **-** | 2 | - |
| Europe | **7** | 7 | 10 | **-** | - | - |
| Asia Pacific/Middle East | **8** | 6 | 3 | **-** | - | * |
| Africa | **-** | - | - | **-** | - | - |
| Other areas | **-** | - | - | **-** | - | - |
| Total consolidated operations | **198** | 188 | 425 | **-** | 2 | - |
| *Equity affiliates* | | | | | | |
| Canada | **19** | 48 | 22 | **-** | - | - |
| Asia Pacific/Middle East | **84** | 108 | 166 | **-** | - | 2 |
| Other areas | **-** | - | * | **-** | - | - |
| Total equity affiliates | **103** | 156 | 188 | **-** | - | 2 |

**Our total proportionate interest was less than one.*

The table below represents the status of our wells drilling at December 31, 2017, and includes wells in the process of drilling or in active completion. It also represents gross and net productive wells, including producing wells and wells capable of production at December 31, 2017.

| **Wells at December 31, 2017** | | | Productive* | | | |
|---|---|---|---|---|---|---|
| | In Progress | | Oil | | Gas | |
| | Gross | Net | Gross | Net | Gross | Net |
| *Consolidated operations* | | | | | | |
| Alaska | 1 | 1 | 1,721 | 769 | - | - |
| Lower 48 | 354 | 179 | 9,984 | 4,781 | 5,222 | 2,364 |
| United States | 355 | 180 | 11,705 | 5,550 | 5,222 | 2,364 |
| Canada | 1 | 1 | 182 | 91 | 42 | 34 |
| Europe | 22 | 3 | 486 | 86 | 181 | 68 |
| Asia Pacific/Middle East | 3 | 1 | 370 | 153 | 55 | 28 |
| Africa | - | - | 825 | 135 | 9 | 2 |
| Total consolidated operations | 381 | 185 | 13,568 | 6,015 | 5,509 | 2,496 |
| *Equity affiliates* | | | | | | |
| Asia Pacific/Middle East | 176 | 47 | - | - | 3,749 | 907 |
| Total equity affiliates | 176 | 47 | - | - | 3,749 | 907 |

**Includes 18 gross and 6 net multiple completion wells.*

| **Acreage at December 31, 2017** | Thousands of Acres | | | |
|---|---|---|---|---|
| | Developed | | Undeveloped | |
| | Gross | Net | Gross | Net |
| *Consolidated operations* | | | | |
| Alaska | 592 | 294 | 1,345 | 1,014 |
| Lower 48 | 2,278 | 1,934 | 10,632 | 8,509 |
| United States | 2,870 | 2,228 | 11,977 | 9,523 |
| Canada | 187 | 105 | 3,251 | 1,772 |
| Europe | 797 | 244 | 2,454 | 720 |
| Asia Pacific/Middle East | 1,596 | 742 | 12,568 | 6,462 |
| Africa | 358 | 59 | 12,545 | 2,049 |
| Other areas | - | - | 560 | 323 |
| Total consolidated operations | 5,808 | 3,378 | 43,355 | 20,849 |
| *Equity affiliates* | | | | |
| Asia Pacific/Middle East | 872 | 201 | 5,445 | 1,432 |
| Total equity affiliates | 872 | 201 | 5,445 | 1,432 |

## Costs Incurred

| Year Ended December 31 | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East * | Africa | Other Areas | Total |
|---|---|---|---|---|---|---|---|---|---|
| | Millions of Dollars | | | | | | | | |
| **2017** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Unproved property acquisition | $ 18 | 267 | 285 | 76 | - | 15 | - | - | 376 |
| Proved property acquisition | - | 35 | 35 | - | - | - | - | - | 35 |
| | 18 | 302 | 320 | 76 | - | 15 | - | - | 411 |
| Exploration | 74 | 399 | 473 | 56 | 52 | 139 | 61 | 42 | 823 |
| Development | 736 | 1,559 | 2,295 | 102 | 784 | 388 | 10 | - | 3,579 |
| | $ 828 | 2,260 | 3,088 | 234 | 836 | 542 | 71 | 42 | 4,813 |
| *Equity affiliates* | | | | | | | | | |
| Unproved property acquisition | $ - | - | - | - | - | - | - | - | - |
| Proved property acquisition | - | - | - | - | - | - | - | - | - |
| | - | - | - | - | - | - | - | - | - |
| Exploration | - | - | - | 6 | - | 38 | - | - | 44 |
| Development | - | - | - | 150 | - | 403 | - | - | 553 |
| | $ - | - | - | 156 | - | 441 | - | - | 597 |
| 2016 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Unproved property acquisition | $ - | 127 | 127 | 59 | - | - | - | - | 186 |
| Proved property acquisition | - | 5 | 5 | 19 | - | - | - | - | 24 |
| | - | 132 | 132 | 78 | - | - | - | - | 210 |
| Exploration | 110 | 656 | 766 | 286 | 65 | 52 | 215 | 67 | 1,451 |
| Development | 720 | 782 | 1,502 | 209 | 62 | 387 | 6 | - | 2,166 |
| | $ 830 | 1,570 | 2,400 | 573 | 127 | 439 | 221 | 67 | 3,827 |
| *Equity affiliates* | | | | | | | | | |
| Unproved property acquisition | $ - | - | - | - | - | 2 | - | - | 2 |
| Proved property acquisition | - | - | - | - | - | - | - | - | - |
| | - | - | - | - | - | 2 | - | - | 2 |
| Exploration | - | - | - | 15 | - | 19 | - | - | 34 |
| Development | - | - | - | 367 | - | 320 | - | - | 687 |
| | $ - | - | - | 382 | - | 341 | - | - | 723 |
| 2015 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Unproved property acquisition | $ - | 168 | 168 | 52 | - | - | - | - | 220 |
| Proved property acquisition | - | 5 | 5 | 1 | - | - | - | - | 6 |
| | - | 173 | 173 | 53 | - | - | - | - | 226 |
| Exploration | 87 | 1,369 | 1,456 | 298 | 107 | 118 | 394 | 47 | 2,420 |
| Development | 1,217 | 2,875 | 4,092 | 827 | 1,742 | 587 | 4 | - | 7,252 |
| | $ 1,304 | 4,417 | 5,721 | 1,178 | 1,849 | 705 | 398 | 47 | 9,898 |
| *Equity affiliates* | | | | | | | | | |
| Unproved property acquisition | $ - | - | - | - | - | - | - | - | - |
| Proved property acquisition | - | - | - | - | - | - | - | - | - |
| | - | - | - | - | - | - | - | - | - |
| Exploration | - | - | - | 17 | - | 60 | - | - | 77 |
| Development | - | - | - | 847 | - | 753 | - | 3 | 1,603 |
| | $ - | - | - | 864 | - | 813 | - | 3 | 1,680 |

**Certain amounts in Asia Pacific/Middle East equity affiliates have been revised in 2016 and 2015 to reflect additional abandonment obligations.*

## Capitalized Costs

| At December 31 | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East* | Africa | Other Areas | Total |
| **2017** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Proved property | $ 18,149 | 35,332 | 53,481 | 6,217 | 27,221 | 14,236 | 889 | - | 102,044 |
| Unproved property | 1,068 | 1,137 | 2,205 | 985 | 290 | 822 | 122 | 67 | 4,491 |
| | 19,217 | 36,469 | 55,686 | 7,202 | 27,511 | 15,058 | 1,011 | 67 | 106,535 |
| Accumulated depreciation, depletion and amortization | 9,497 | 24,211 | 33,708 | 1,582 | 18,068 | 8,916 | 312 | 9 | 62,595 |
| | $ 9,720 | 12,258 | 21,978 | 5,620 | 9,443 | 6,142 | 699 | 58 | 43,940 |
| *Equity affiliates* | | | | | | | | | |
| Proved property | $ - | - | - | - | - | 9,750 | - | - | 9,750 |
| Unproved property | - | - | - | - | - | 2,215 | - | - | 2,215 |
| | - | - | - | - | - | 11,965 | - | - | 11,965 |
| Accumulated depreciation, depletion and amortization | - | - | - | - | - | 5,342 | - | - | 5,342 |
| | $ - | - | - | - | - | 6,623 | - | - | 6,623 |
| 2016 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Proved property | $ 17,376 | 46,050 | 63,426 | 16,970 | 24,858 | 13,837 | 879 | - | 119,970 |
| Unproved property | 1,099 | 1,376 | 2,475 | 1,435 | 269 | 787 | 123 | 61 | 5,150 |
| | 18,475 | 47,426 | 65,901 | 18,405 | 25,127 | 14,624 | 1,002 | 61 | 125,120 |
| Accumulated depreciation, depletion and amortization | 8,548 | 26,858 | 35,406 | 10,344 | 15,754 | 7,635 | 297 | 1 | 69,437 |
| | $ 9,927 | 20,568 | 30,495 | 8,061 | 9,373 | 6,989 | 705 | 60 | 55,683 |
| *Equity affiliates* | | | | | | | | | |
| Proved property | $ - | - | - | 9,459 | - | 8,839 | - | - | 18,298 |
| Unproved property | - | - | - | 891 | - | 2,756 | - | - | 3,647 |
| | - | - | - | 10,350 | - | 11,595 | - | - | 21,945 |
| Accumulated depreciation, depletion and amortization | - | - | - | 1,906 | - | 1,369 | - | - | 3,275 |
| | $ - | - | - | 8,444 | - | 10,226 | - | - | 18,670 |

**Certain amounts in Asia Pacific/Middle East equity affiliates have been revised in 2016 to reflect additional abandonment obligations.*

**Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities**

In accordance with SEC and FASB requirements, amounts were computed using 12-month average prices (adjusted only for existing contractual terms) and end-of-year costs, appropriate statutory tax rates and a prescribed 10 percent discount factor. Twelve-month average prices are calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. For all years, continuation of year-end economic conditions was assumed. The calculations were based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, were not considered. The calculations also require assumptions as to the timing of future production of proved reserves and the timing and amount of future development costs, including dismantlement, and future production costs, including taxes other than income taxes.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

### Discounted Future Net Cash Flows

| | | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
| **2017** | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Future cash inflows | $ | 44,969 | 44,556 | 89,525 | 5,479 | 23,137 | 15,207 | 13,181 | 146,529 |
| Less: | | | | | | | | | |
| Future production costs | | 29,524 | 18,947 | 48,471 | 4,417 | 8,128 | 5,398 | 1,401 | 67,815 |
| Future development costs | | 7,255 | 10,881 | 18,136 | 696 | 8,758 | 2,511 | 537 | 30,638 |
| Future income tax provisions | | 53 | 2,375 | 2,428 | - | 3,333 | 2,459 | 10,356 | 18,576 |
| Future net cash flows | | 8,137 | 12,353 | 20,490 | 366 | 2,918 | 4,839 | 887 | 29,500 |
| 10 percent annual discount | | 2,712 | 4,358 | 7,070 | 78 | 289 | 1,032 | 422 | 8,891 |
| Discounted future net cash flows | $ | 5,425 | 7,995 | 13,420 | 288 | 2,629 | 3,807 | 465 | 20,609 |
| *Equity affiliates* | | | | | | | | | |
| Future cash inflows | $ | - | - | - | - | - | 23,222 | - | 23,222 |
| Less: | | | | | | | | | |
| Future production costs | | - | - | - | - | - | 12,984 | - | 12,984 |
| Future development costs | | - | - | - | - | - | 1,444 | - | 1,444 |
| Future income tax provisions | | - | - | - | - | - | 2,083 | - | 2,083 |
| Future net cash flows | | - | - | - | - | - | 6,711 | - | 6,711 |
| 10 percent annual discount | | - | - | - | - | - | 2,316 | - | 2,316 |
| Discounted future net cash flows | $ | - | - | - | - | - | 4,395 | - | 4,395 |
| *Total company* | | | | | | | | | |
| Discounted future net cash flows | $ | 5,425 | 7,995 | 13,420 | 288 | 2,629 | 8,202 | 465 | 25,004 |

| | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
| 2016 | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| Future cash inflows | $ 29,697 | 31,963 | 61,660 | 4,739 | 18,533 | 12,770 | 10,715 | 108,417 |
| Less: | | | | | | | | |
| Future production costs | 24,965 | 16,936 | 41,901 | 5,103 | 7,469 | 5,288 | 1,420 | 61,181 |
| Future development costs | 7,961 | 8,932 | 16,893 | 1,586 | 9,949 | 2,777 | 537 | 31,742 |
| Future income tax provisions (benefit) | - | 744 | 744 | - | (325) | 1,563 | 7,885 | 9,867 |
| Future net cash flows | (3,229) | 5,351 | 2,122 | (1,950) | 1,440 | 3,142 | 873 | 5,627 |
| 10 percent annual discount | (3,143) | 976 | (2,167) | (1,297) | (2) | 572 | 370 | (2,524) |
| Discounted future net cash flows | $ (86) | 4,375 | 4,289 | (653) | 1,442 | 2,570 | 503 | 8,151 |
| | | | | | | | | |
| *Equity affiliates* | | | | | | | | |
| Future cash inflows | $ - | - | - | 15,139 | - | 17,829 | - | 32,968 |
| Less: | | | | | | | | |
| Future production costs | - | - | - | 8,514 | - | 10,620 | - | 19,134 |
| Future development costs | - | - | - | 4,993 | - | 980 | - | 5,973 |
| Future income tax provisions | - | - | - | 164 | - | 1,309 | - | 1,473 |
| Future net cash flows | - | - | - | 1,468 | - | 4,920 | - | 6,388 |
| 10 percent annual discount | - | - | - | 540 | - | 1,911 | - | 2,451 |
| Discounted future net cash flows | $ - | - | - | 928 | - | 3,009 | - | 3,937 |
| | | | | | | | | |
| *Total company* | | | | | | | | |
| Discounted future net cash flows | $ (86) | 4,375 | 4,289 | 275 | 1,442 | 5,579 | 503 | 12,088 |

| | Millions of Dollars | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
| 2015 | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| Future cash inflows | $ 44,054 | 42,575 | 86,629 | 22,317 | 27,782 | 19,368 | 13,875 | 169,971 |
| Less: | | | | | | | | |
| Future production costs | 32,732 | 21,638 | 54,370 | 13,103 | 10,574 | 7,529 | 1,422 | 86,998 |
| Future development costs | 9,885 | 12,967 | 22,852 | 6,471 | 12,793 | 2,884 | 437 | 45,437 |
| Future income tax provisions | - | 844 | 844 | - | 1,506 | 2,708 | 10,998 | 16,056 |
| Future net cash flows | 1,437 | 7,126 | 8,563 | 2,743 | 2,909 | 6,247 | 1,018 | 21,480 |
| 10 percent annual discount | (502) | 1,573 | 1,071 | 1,265 | 733 | 1,349 | 500 | 4,918 |
| Discounted future net cash flows | $ 1,939 | 5,553 | 7,492 | 1,478 | 2,176 | 4,898 | 518 | 16,562 |
| *Equity affiliates* | | | | | | | | |
| Future cash inflows | $ - | - | - | 36,211 | - | 34,257 | - | 70,468 |
| Less: | | | | | | | | |
| Future production costs | - | - | - | 16,417 | - | 17,874 | - | 34,291 |
| Future development costs | - | - | - | 11,869 | - | 2,391 | - | 14,260 |
| Future income tax provisions | - | - | - | 1,648 | - | 3,117 | - | 4,765 |
| Future net cash flows | - | - | - | 6,277 | - | 10,875 | - | 17,152 |
| 10 percent annual discount | - | - | - | 3,827 | - | 4,298 | - | 8,125 |
| Discounted future net cash flows | $ - | - | - | 2,450 | - | 6,577 | - | 9,027 |
| *Total company* | | | | | | | | |
| Discounted future net cash flows | $ 1,939 | 5,553 | 7,492 | 3,928 | 2,176 | 11,475 | 518 | 25,589 |

**Sources of Change in Discounted Future Net Cash Flows**

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Consolidated Operations | | | Equity Affiliates | | | Total Company | | |
| | **2017** | 2016 | 2015 | **2017** | 2016 | 2015 | **2017** | 2016 | 2015 |
| Discounted future net cash flows at the beginning of the year | $ **8,151** | 16,562 | 56,348 | **3,937** | 9,027 | 26,869 | **12,088** | 25,589 | 83,217 |
| Changes during the year | | | | | | | | | |
| Revenues less production costs for the year | **(9,844)** | (6,313) | (8,158) | **(1,341)** | (956) | (966) | **(11,185)** | (7,269) | (9,124) |
| Net change in prices and production costs | **19,310** | (16,476) | (82,923) | **2,750** | (9,317) | (27,670) | **22,060** | (25,793) | (110,593) |
| Extensions, discoveries and improved recovery, less estimated future costs | **1,445** | 1,358 | 1,791 | **(4)** | (77) | 319 | **1,441** | 1,281 | 2,110 |
| Development costs for the year | **3,653** | 3,118 | 6,854 | **426** | 722 | 1,493 | **4,079** | 3,840 | 8,347 |
| Changes in estimated future development costs | **1,225** | 6,646 | 2,073 | **(64)** | 2,435 | (227) | **1,161** | 9,081 | 1,846 |
| Purchases of reserves in place, less estimated future costs | **-** | 2 | - | **-** | - | - | **-** | 2 | - |
| Sales of reserves in place, less estimated future costs | **(855)** | (123) | (424) | **(786)** | - | (38) | **(1,641)** | (123) | (462) |
| Revisions of previous quantity estimates | **2,300** | (3,252) | (1,790) | **(648)** | (436) | 938 | **1,652** | (3,688) | (852) |
| Accretion of discount | **1,313** | 2,540 | 9,342 | **413** | 1,058 | 3,297 | **1,726** | 3,598 | 12,639 |
| Net change in income taxes | **(6,089)** | 4,089 | 33,449 | **(288)** | 1,481 | 5,012 | **(6,377)** | 5,570 | 38,461 |
| Total changes | **12,458** | (8,411) | (39,786) | **458** | (5,090) | (17,842) | **12,916** | (13,501) | (57,628) |
| Discounted future net cash flows at year end | $ **20,609** | 8,151 | 16,562 | **4,395** | 3,937 | 9,027 | **25,004** | 12,088 | 25,589 |

- The net change in prices and production costs is the beginning-of-year reserve-production forecast multiplied by the net annual change in the per-unit sales price and production cost, discounted at 10 percent.
- Purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.
- Revisions of previous quantity estimates are calculated using production forecast changes for the year, including changes in the timing of production, multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.
- The accretion of discount is 10 percent of the prior year's discounted future cash inflows, less future production and development costs.
- The net change in income taxes is the annual change in the discounted future income tax provisions.

**Selected Quarterly Financial Data** (Unaudited)

| | Millions of Dollars | | | | Per Share of Common Stock | |
|---|---|---|---|---|---|---|
| | | | | | Net Income (Loss) Attributable to ConocoPhillips | |
| | Sales and Other Operating Revenues | Income (Loss) Before Income Taxes | Net Income (Loss) | Net Income (Loss) Attributable to ConocoPhillips | Basic | Diluted |
| **2017** | | | | | | |
| First | **$ 7,518** | **(232)** | **599** | **586** | **0.47** | **0.47** |
| Second | **6,781** | **(4,361)** | **(3,426)** | **(3,440)** | **(2.78)** | **(2.78)** |
| Third | **6,688** | **653** | **436** | **420** | **0.35** | **0.34** |
| Fourth | **8,119** | **1,325** | **1,598** | **1,579** | **1.32** | **1.32** |
| 2016 | | | | | | |
| First | $ 5,121 | (2,224) | (1,456) | (1,469) | (1.18) | (1.18) |
| Second | 5,348 | (1,644) | (1,058) | (1,071) | (0.86) | (0.86) |
| Third | 6,415 | (1,654) | (1,026) | (1,040) | (0.84) | (0.84) |
| Fourth | 6,809 | (8) | (19) | (35) | (0.03) | (0.03) |

*For additional information on the commodity price environment, see the Business Environment and Executive Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations.*

**Supplementary Information—Condensed Consolidating Financial Information**

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company and ConocoPhillips Canada Funding Company I, with respect to publicly held debt securities. ConocoPhillips Company is 100 percent owned by ConocoPhillips. ConocoPhillips Canada Funding Company I is an indirect, 100 percent owned subsidiary of ConocoPhillips Company. ConocoPhillips and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Canada Funding Company I, with respect to their publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial information presents the results of operations, financial position and cash flows for:

- ConocoPhillips, ConocoPhillips Company and ConocoPhillips Canada Funding Company I (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).
- All other nonguarantor subsidiaries of ConocoPhillips.
- The consolidating adjustments necessary to present ConocoPhillips' results on a consolidated basis.

In 2015, ConocoPhillips received a $3.5 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2016, ConocoPhillips received a $2.3 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2016, ConocoPhillips Canada Funding Company I repaid $1.25 billion of external debt. This transaction was reflected in the full-year 2016 condensed consolidating financial statements.

In 2017, ConocoPhillips Company received a $9.8 billion return of capital from a nonguarantor subsidiary to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2017, ConocoPhillips received a $5.0 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2017, ConocoPhillips received a $3.0 billion distribution from ConocoPhillips Company to settle certain accumulated intercompany balances. This consisted of a $2.8 billion return of capital and a $0.2 billion return of earnings. This transaction had no impact on our consolidated financial statements.

In 2017, ConocoPhillips Company received a $1.4 billion loan repayment from a nonguarantor subsidiary to settle certain accumulated intercompany balances. This transaction had no impact on our consolidated financial statements.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes.

| Income Statement | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
|---|---|---|---|---|---|---|
| | Millions of Dollars | | | | | |
| | Year Ended December 31, 2017 | | | | | |
| **Revenues and Other Income** | | | | | | |
| Sales and other operating revenues | $ - | 12,433 | - | 16,673 | - | 29,106 |
| Equity in earnings (losses) of affiliates | (454) | 2,047 | - | 630 | (1,451) | 772 |
| Gain on dispositions | - | 916 | - | 1,261 | - | 2,177 |
| Other income | 2 | 35 | - | 492 | - | 529 |
| Intercompany revenues | 48 | 291 | 170 | 3,405 | (3,914) | - |
| Total Revenues and Other Income | (404) | 15,722 | 170 | 22,461 | (5,365) | 32,584 |
| **Costs and Expenses** | | | | | | |
| Purchased commodities | - | 11,145 | - | 4,580 | (3,250) | 12,475 |
| Production and operating expenses | - | 832 | - | 4,358 | (17) | 5,173 |
| Selling, general and administrative expenses | 9 | 476 | - | 82 | (6) | 561 |
| Exploration expenses | - | 544 | - | 394 | - | 938 |
| Depreciation, depletion and amortization | - | 855 | - | 5,990 | - | 6,845 |
| Impairments | - | 1,159 | - | 5,442 | - | 6,601 |
| Taxes other than income taxes | - | 140 | - | 669 | - | 809 |
| Accretion on discounted liabilities | - | 32 | - | 330 | - | 362 |
| Interest and debt expense | 420 | 664 | 147 | 508 | (641) | 1,098 |
| Foreign currency transaction (gains) losses | (43) | 11 | 156 | (89) | - | 35 |
| Other expense | 267 | 35 | - | - | - | 302 |
| Total Costs and Expenses | 653 | 15,893 | 303 | 22,264 | (3,914) | 35,199 |
| Income (Loss) before income taxes | (1,057) | (171) | (133) | 197 | (1,451) | (2,615) |
| Income tax provision (benefit) | (202) | 283 | 7 | (1,910) | - | (1,822) |
| Net income (loss) | (855) | (454) | (140) | 2,107 | (1,451) | (793) |
| Less: net income attributable to noncontrolling interests | - | - | - | (62) | - | (62) |
| **Net Income (Loss) Attributable to ConocoPhillips** | $ (855) | (454) | (140) | 2,045 | (1,451) | (855) |
| **Comprehensive Income (Loss) Attributable to ConocoPhillips** | $ (180) | 221 | 23 | 2,703 | (2,947) | (180) |
| **Income Statement** | Year Ended December 31, 2016 | | | | | |
| **Revenues and Other Income** | | | | | | |
| Sales and other operating revenues | $ - | 10,352 | - | 13,341 | - | 23,693 |
| Equity in earnings (losses) of affiliates | (3,351) | (1,051) | - | (91) | 4,545 | 52 |
| Gain on dispositions | - | 120 | - | 240 | - | 360 |
| Other income | 1 | (11) | - | 265 | - | 255 |
| Intercompany revenues | 88 | 277 | 220 | 3,036 | (3,621) | - |
| Total Revenues and Other Income | (3,262) | 9,687 | 220 | 16,791 | 924 | 24,360 |
| **Costs and Expenses** | | | | | | |
| Purchased commodities | - | 9,144 | - | 3,562 | (2,712) | 9,994 |
| Production and operating expenses | - | 779 | - | 5,131 | (243) | 5,667 |
| Selling, general and administrative expenses | 8 | 581 | - | 140 | (6) | 723 |
| Exploration expenses | - | 1,231 | - | 684 | - | 1,915 |
| Depreciation, depletion and amortization | - | 1,178 | - | 7,884 | - | 9,062 |
| Impairments | - | 67 | - | 72 | - | 139 |
| Taxes other than income taxes | - | 162 | - | 577 | - | 739 |
| Accretion on discounted liabilities | - | 46 | - | 379 | - | 425 |
| Interest and debt expense | 506 | 622 | 207 | 570 | (660) | 1,245 |
| Foreign currency transaction (gains) losses | (19) | 2 | 174 | (176) | - | (19) |
| Total Costs and Expenses | 495 | 13,812 | 381 | 18,823 | (3,621) | 29,890 |
| Loss before income taxes | (3,757) | (4,125) | (161) | (2,032) | 4,545 | (5,530) |
| Income tax benefit | (142) | (774) | (9) | (1,046) | - | (1,971) |
| Net loss | (3,615) | (3,351) | (152) | (986) | 4,545 | (3,559) |
| Less: net income attributable to noncontrolling interests | - | - | - | (56) | - | (56) |
| **Net Loss Attributable to ConocoPhillips** | $ (3,615) | (3,351) | (152) | (1,042) | 4,545 | (3,615) |
| **Comprehensive Loss Attributable to ConocoPhillips** | $ (3,561) | (3,297) | (27) | (952) | 4,276 | (3,561) |

| Income Statement | | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
|---|---|---|---|---|---|---|---|
| | | Millions of Dollars | | | | | |
| | | Year Ended December 31, 2015 | | | | | |
| **Revenues and Other Income** | | | | | | | |
| Sales and other operating revenues | $ | - | 11,473 | - | 18,091 | - | 29,564 |
| Equity in earnings (losses) of affiliates | | (4,081) | (1,950) | - | 1,364 | 5,322 | 655 |
| Gain on dispositions | | - | 332 | - | 259 | - | 591 |
| Other income | | - | 12 | - | 113 | - | 125 |
| Intercompany revenues | | 74 | 341 | 246 | 3,365 | (4,026) | - |
| Total Revenues and Other Income | | (4,007) | 10,208 | 246 | 23,192 | 1,296 | 30,935 |
| **Costs and Expenses** | | | | | | | |
| Purchased commodities | | - | 9,905 | - | 5,838 | (3,317) | 12,426 |
| Production and operating expenses | | - | 1,469 | - | 5,585 | (38) | 7,016 |
| Selling, general and administrative expenses | | 9 | 744 | 1 | 209 | (10) | 953 |
| Exploration expenses | | - | 2,093 | - | 2,099 | - | 4,192 |
| Depreciation, depletion and amortization | | - | 1,201 | - | 7,912 | - | 9,113 |
| Impairments | | - | 15 | - | 2,230 | - | 2,245 |
| Taxes other than income taxes | | - | 173 | - | 728 | - | 901 |
| Accretion on discounted liabilities | | - | 58 | - | 425 | - | 483 |
| Interest and debt expense | | 485 | 423 | 226 | 447 | (661) | 920 |
| Foreign currency transaction (gains) losses | | 114 | 1 | (708) | 518 | - | (75) |
| Total Costs and Expenses | | 608 | 16,082 | (481) | 25,991 | (4,026) | 38,174 |
| Income (loss) before income taxes | | (4,615) | (5,874) | 727 | (2,799) | 5,322 | (7,239) |
| Income tax provision (benefit) | | (187) | (1,793) | 21 | (909) | - | (2,868) |
| Net income (loss) | | (4,428) | (4,081) | 706 | (1,890) | 5,322 | (4,371) |
| Less: net income attributable to noncontrolling interests | | - | - | - | (57) | - | (57) |
| **Net Income (Loss) Attributable to ConocoPhillips** | $ | (4,428) | (4,081) | 706 | (1,947) | 5,322 | (4,428) |
| **Comprehensive Income (Loss) Attributable to ConocoPhillips** | $ | (8,773) | (8,426) | 71 | (6,705) | 15,060 | (8,773) |

| Balance Sheet | | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
|---|---|---|---|---|---|---|---|
| | | Millions of Dollars | | | | | |
| | | At December 31, 2017 | | | | | |
| **Assets** | | | | | | | |
| Cash and cash equivalents | $ | - | 234 | 4 | 6,087 | - | 6,325 |
| Short-term investments | | - | - | - | 1,873 | - | 1,873 |
| Accounts and notes receivable | | 24 | 2,255 | 35 | 4,870 | (2,864) | 4,320 |
| Investment in Cenovus Energy | | - | 1,899 | - | - | - | 1,899 |
| Inventories | | - | 163 | - | 897 | - | 1,060 |
| Prepaid expenses and other current assets | | 1 | 278 | 6 | 779 | (29) | 1,035 |
| Total Current Assets | | 25 | 4,829 | 45 | 14,506 | (2,893) | 16,512 |
| Investments, loans and long-term receivables* | | 29,400 | 47,974 | 2,533 | 15,050 | (84,897) | 10,060 |
| Net properties, plants and equipment | | - | 4,230 | - | 41,930 | (477) | 45,683 |
| Other assets | | 15 | 1,146 | 186 | 1,302 | (1,542) | 1,107 |
| Total Assets | $ | 29,440 | 58,179 | 2,764 | 72,788 | (89,809) | 73,362 |
| **Liabilities and Stockholders' Equity** | | | | | | | |
| Accounts payable | $ | - | 3,094 | 1 | 3,799 | (2,864) | 4,030 |
| Short-term debt | | (5) | 2,505 | 7 | 77 | (9) | 2,575 |
| Accrued income and other taxes | | - | 107 | - | 931 | - | 1,038 |
| Employee benefit obligations | | - | 554 | - | 171 | - | 725 |
| Other accruals | | 85 | 314 | 48 | 612 | (30) | 1,029 |
| Total Current Liabilities | | 80 | 6,574 | 56 | 5,590 | (2,903) | 9,397 |
| Long-term debt | | 3,787 | 9,321 | 1,703 | 2,794 | (477) | 17,128 |
| Asset retirement obligations and accrued environmental costs | | - | 432 | - | 7,199 | - | 7,631 |
| Deferred income taxes | | - | - | - | 6,263 | (981) | 5,282 |
| Employee benefit obligations | | - | 1,335 | - | 519 | - | 1,854 |
| Other liabilities and deferred credits* | | 1,528 | 5,229 | 926 | 9,215 | (15,629) | 1,269 |
| Total Liabilities | | 5,395 | 22,891 | 2,685 | 31,580 | (19,990) | 42,561 |
| Retained earnings | | 22,867 | 13,317 | (681) | 11,958 | (18,070) | 29,391 |
| Other common stockholders' equity | | 1,178 | 21,971 | 760 | 29,056 | (51,749) | 1,216 |
| Noncontrolling interests | | - | - | - | 194 | - | 194 |
| Total Liabilities and Stockholders' Equity | $ | 29,440 | 58,179 | 2,764 | 72,788 | (89,809) | 73,362 |

| Balance Sheet | | At December 31, 2016 | | | | | |
|---|---|---|---|---|---|---|---|
| **Assets** | | | | | | | |
| Cash and cash equivalents | $ | - | 358 | 13 | 3,239 | - | 3,610 |
| Short-term investments | | - | - | - | 50 | - | 50 |
| Accounts and notes receivable | | 22 | 1,968 | 23 | 6,103 | (4,702) | 3,414 |
| Inventories | | - | 84 | - | 934 | - | 1,018 |
| Prepaid expenses and other current assets | | 2 | 116 | 8 | 415 | (24) | 517 |
| Total Current Assets | | 24 | 2,526 | 44 | 10,741 | (4,726) | 8,609 |
| Investments, loans and long-term receivables* | | 37,901 | 64,434 | 2,296 | 31,643 | (114,602) | 21,672 |
| Net properties, plants and equipment | | - | 6,301 | - | 52,030 | - | 58,331 |
| Other assets | | 40 | 2,194 | 220 | 1,240 | (2,534) | 1,160 |
| Total Assets | $ | 37,965 | 75,455 | 2,560 | 95,654 | (121,862) | 89,772 |
| **Liabilities and Stockholders' Equity** | | | | | | | |
| Accounts payable | $ | - | 4,683 | 1 | 3,671 | (4,702) | 3,653 |
| Short-term debt | | (10) | 999 | 6 | 94 | - | 1,089 |
| Accrued income and other taxes | | - | 85 | - | 399 | - | 484 |
| Employee benefit obligations | | - | 489 | - | 200 | - | 689 |
| Other accruals | | 171 | 271 | 40 | 536 | (24) | 994 |
| Total Current Liabilities | | 161 | 6,527 | 47 | 4,900 | (4,726) | 6,909 |
| Long-term debt | | 8,975 | 12,635 | 1,710 | 2,866 | - | 26,186 |
| Asset retirement obligations and accrued environmental costs | | - | 925 | - | 7,500 | - | 8,425 |
| Deferred income taxes | | - | - | - | 10,972 | (2,023) | 8,949 |
| Employee benefit obligations | | - | 1,901 | - | 651 | - | 2,552 |
| Other liabilities and deferred credits* | | 417 | 10,391 | 748 | 17,832 | (27,863) | 1,525 |
| Total Liabilities | | 9,553 | 32,379 | 2,505 | 44,721 | (34,612) | 54,546 |
| Retained earnings | | 25,025 | 14,015 | (541) | 12,883 | (19,834) | 31,548 |
| Other common stockholders' equity | | 3,387 | 29,061 | 596 | 37,798 | (67,416) | 3,426 |
| Noncontrolling interests | | - | - | - | 252 | - | 252 |
| Total Liabilities and Stockholders' Equity | $ | 37,965 | 75,455 | 2,560 | 95,654 | (121,862) | 89,772 |

**Includes intercompany loans.*

| Statement of Cash Flows | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
|---|---|---|---|---|---|---|
| | Millions of Dollars | | | | | |
| | Year Ended December 31, 2017 | | | | | |
| **Cash Flows From Operating Activities** | | | | | | |
| Net Cash Provided by (Used in) Operating Activities | $ 71 | 1,183 | (74) | 8,931 | (3,034) | 7,077 |
| **Cash Flows From Investing Activities** | | | | | | |
| Capital expenditures and investments | - | (1,663) | - | (3,795) | 867 | (4,591) |
| Working capital changes associated with investing activities | - | 194 | - | (62) | - | 132 |
| Proceeds from asset dispositions | 7,765 | 11,146 | - | 12,796 | (17,847) | 13,860 |
| Net purchases of short-term investments | - | - | - | (1,790) | - | (1,790) |
| Long-term advances/loans—related parties | - | (214) | - | (85) | 299 | - |
| Collection of advances/loans—related parties | 658 | 1,527 | - | 2,196 | (4,266) | 115 |
| Intercompany cash management | 1,151 | 101 | - | (1,252) | - | - |
| Other | - | (8) | - | 44 | - | 36 |
| Net Cash Provided by Investing Activities | 9,574 | 11,083 | - | 8,052 | (20,947) | 7,762 |
| **Cash Flows From Financing Activities** | | | | | | |
| Issuance of debt | - | 20 | 65 | 214 | (299) | - |
| Repayment of debt | (5,459) | (4,411) | - | (2,272) | 4,266 | (7,876) |
| Issuance of company common stock | 115 | - | - | - | (178) | (63) |
| Repurchase of company common stock | (3,000) | - | - | - | - | (3,000) |
| Dividends paid | (1,305) | (235) | - | (2,977) | 3,212 | (1,305) |
| Other | 4 | (7,765) | - | (9,331) | 16,980 | (112) |
| Net Cash Provided by (Used in) Financing Activities | (9,645) | (12,391) | 65 | (14,366) | 23,981 | (12,356) |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | - | 1 | - | 231 | - | 232 |
| **Net Change in Cash and Cash Equivalents** | - | (124) | (9) | 2,848 | - | 2,715 |
| Cash and cash equivalents at beginning of period | - | 358 | 13 | 3,239 | - | 3,610 |
| Cash and Cash Equivalents at End of Period | $ - | 234 | 4 | 6,087 | - | 6,325 |

| Statement of Cash Flows | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
|---|---|---|---|---|---|---|
| | Year Ended December 31, 2016 | | | | | |
| **Cash Flows From Operating Activities** | | | | | | |
| Net Cash Provided by (Used in) Operating Activities | $ (306) | (322) | (2) | 5,903 | (870) | 4,403 |
| **Cash Flows From Investing Activities** | | | | | | |
| Capital expenditures and investments | - | (989) | - | (4,281) | 401 | (4,869) |
| Working capital changes associated with investing activities | - | (126) | - | (205) | - | (331) |
| Proceeds from asset dispositions | 2,300 | 266 | - | 1,114 | (2,394) | 1,286 |
| Net purchases of short-term investments | - | - | - | (51) | - | (51) |
| Long-term advances/loans—related parties | - | (812) | - | - | 812 | - |
| Collection of advances/loans—related parties | - | 391 | 1,250 | 272 | (1,805) | 108 |
| Intercompany cash management | (2,214) | 1,433 | - | 781 | - | - |
| Other | - | 1 | - | (3) | - | (2) |
| Net Cash Provided by (Used in) Investing Activities | 86 | 164 | 1,250 | (2,373) | (2,986) | (3,859) |
| **Cash Flows From Financing Activities** | | | | | | |
| Issuance of debt | 1,600 | 2,994 | - | 812 | (812) | 4,594 |
| Repayment of debt | (150) | (164) | (1,250) | (2,492) | 1,805 | (2,251) |
| Issuance of company common stock | 148 | - | - | - | (211) | (63) |
| Repurchase of company common stock | (126) | - | - | - | - | (126) |
| Dividends paid | (1,253) | - | - | (1,081) | 1,081 | (1,253) |
| Other | 1 | (2,315) | - | 184 | 1,993 | (137) |
| Net Cash Provided by (Used in) Financing Activities | 220 | 515 | (1,250) | (2,577) | 3,856 | 764 |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | - | (3) | - | (63) | - | (66) |
| **Net Change in Cash and Cash Equivalents** | - | 354 | (2) | 890 | - | 1,242 |
| Cash and cash equivalents at beginning of period | - | 4 | 15 | 2,349 | - | 2,368 |
| Cash and Cash Equivalents at End of Period | $ - | 358 | 13 | 3,239 | - | 3,610 |

| Statement of Cash Flows | ConocoPhillips | ConocoPhillips Company | ConocoPhillips Canada Funding Company I | All Other Subsidiaries | Consolidating Adjustments | Total Consolidated |
|---|---|---|---|---|---|---|
| | Millions of Dollars | | | | | |
| | Year Ended December 31, 2015 | | | | | |
| **Cash Flows From Operating Activities** | | | | | | |
| Net Cash Provided by (Used in) Operating Activities | $ (225) | 245 | 9 | 7,519 | 24 | 7,572 |
| **Cash Flows From Investing Activities** | | | | | | |
| Capital expenditures and investments | - | (3,064) | - | (8,386) | 1,400 | (10,050) |
| Working capital changes associated with investing activities | - | (4) | - | (964) | - | (968) |
| Proceeds from asset dispositions | 3,500 | 826 | - | 1,225 | (3,599) | 1,952 |
| Long-term advances/loans—related parties | - | (278) | - | (2,245) | 2,523 | - |
| Collection of advances/loans—related parties | - | - | - | 205 | (100) | 105 |
| Intercompany cash management | 102 | 46 | - | (148) | - | - |
| Other | - | 304 | - | 1 | 1 | 306 |
| Net Cash Provided by (Used in) Investing Activities | 3,602 | (2,170) | - | (10,312) | 225 | (8,655) |
| **Cash Flows From Financing Activities** | | | | | | |
| Issuance of debt | - | 4,743 | - | 278 | (2,523) | 2,498 |
| Repayment of debt | - | (100) | - | (103) | 100 | (103) |
| Issuance of company common stock | 283 | - | - | (2) | (363) | (82) |
| Dividends paid | (3,664) | - | - | (339) | 339 | (3,664) |
| Other | 4 | (3,484) | - | 1,204 | 2,198 | (78) |
| Net Cash Provided by (Used in) Financing Activities | (3,377) | 1,159 | - | 1,038 | (249) | (1,429) |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | - | - | (1) | (181) | - | (182) |
| **Net Change in Cash and Cash Equivalents** | - | (766) | 8 | (1,936) | - | (2,694) |
| Cash and cash equivalents at beginning of period | - | 770 | 7 | 4,285 | - | 5,062 |
| Cash and Cash Equivalents at End of Period | $ - | 4 | 15 | 2,349 | - | 2,368 |

## Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## Item 9A. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures designed to ensure information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the Act), is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of December 31, 2017, with the participation of our management, our Chairman and Chief Executive Officer (principal executive officer) and our Executive Vice President, Finance, Commercial and Chief Financial Officer (principal financial officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Act, of ConocoPhillips' disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman and Chief Executive Officer and our Executive Vice President, Finance, Commercial and Chief Financial Officer concluded our disclosure controls and procedures were operating effectively as of December 31, 2017.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

### Management's Annual Report on Internal Control Over Financial Reporting

This report is included in Item 8 on page 76 and is incorporated herein by reference.

### Report of Independent Registered Public Accounting Firm

This report is included in Item 8 on page 78 and is incorporated herein by reference.

## Item 9B. OTHER INFORMATION

None.

## PART III

### Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our executive officers appears in Part I of this report on page 26.

**Code of Business Ethics and Conduct for Directors and Employees**

We have a Code of Business Ethics and Conduct for Directors and Employees (Code of Ethics), including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have posted a copy of our Code of Ethics on the "Corporate Governance" section of our internet website at *www.conocophillips.com* (within the Investors>Corporate Governance section). Any waivers of the Code of Ethics must be approved, in advance, by our full Board of Directors. Any amendments to, or waivers from, the Code of Ethics that apply to our executive officers and directors will be posted on the "Corporate Governance" section of our internet website.

All other information required by Item 10 of Part III will be included in our Proxy Statement relating to our 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2018, and is incorporated herein by reference.*

### Item 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2018, and is incorporated herein by reference.*

### Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2018, and is incorporated herein by reference.*

### Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2018, and is incorporated herein by reference.*

### Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2018, and is incorporated herein by reference.*

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**Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in our 2018 Proxy Statement are not deemed to be a part of this Annual Report on Form 10-K or deemed to be filed with the Commission as a part of this report.*

## PART IV

### Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements and Supplementary Data
The financial statements and supplementary information listed in the Index to Financial Statements, which appears on page 75, are filed as part of this annual report.

2. Financial Statement Schedules
Schedule II—Valuation and Qualifying Accounts, appears below. All other schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to consolidated financial statements.

3. Exhibits
The exhibits listed in the Index to Exhibits, which appears on pages 177 through 187, are filed as part of this annual report.

### SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS (Consolidated)

**ConocoPhillips**

| | Millions of Dollars | | | | |
|---|---|---|---|---|---|
| Description | Balance at January 1 | Charged to Expense | Other(a) | Deductions | Balance at December 31 |
| **2017** | | | | | |
| Deducted from asset accounts: | | | | | |
| Allowance for doubtful accounts and notes receivable | **$ 5** | **2** | **-** | **(3)(b)** | **4** |
| Deferred tax asset valuation allowance | **675** | **560 (c)** | **19** | **-** | **1,254** |
| Included in other liabilities: | | | | | |
| Restructuring accruals | **80** | **65** | **1** | **(93)(d)** | **53** |
| 2016 | | | | | |
| Deducted from asset accounts: | | | | | |
| Allowance for doubtful accounts and notes receivable | $ 7 | 3 | (1) | (4)(b) | 5 |
| Deferred tax asset valuation allowance | 734 | (31) | (12) | (16) | 675 |
| Included in other liabilities: | | | | | |
| Restructuring accruals | 156 | 129 | 1 | (206)(d) | 80 |
| 2015 | | | | | |
| Deducted from asset accounts: | | | | | |
| Allowance for doubtful accounts and notes receivable | $ 5 | 4 | (2) | - (b) | 7 |
| Deferred tax asset valuation allowance | 970 | 6 | (21) | (221) | 734 |
| Included in other liabilities: | | | | | |
| Restructuring accruals | 61 | 303 | (8) | (200)(d) | 156 |

*(a)Represents acquisitions/dispositions/revisions and the effect of translating foreign financial statements.*
*(b)Amounts charged off less recoveries of amounts previously charged off.*
*(c)Includes an adjustment to the U.S. tax basis due to U.S. Tax Legislation.*
*(d)Benefit payments.*

**CONOCOPHILLIPS**

**INDEX TO EXHIBITS**

| Exhibit Number | Description |
|---|---|
| 2.1 | Separation and Distribution Agreement Between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 2.2†‡ | Purchase and Sale Agreement, dated March 29, 2017, by and among ConocoPhillips Company, ConocoPhillips Canada Resources Corp., ConocoPhillips Canada Energy Partnership, ConocoPhillips Western Canada Partnership, ConocoPhillips Canada (BRC) Partnership, ConocoPhillips Canada E&P ULC, and Cenovus Energy Inc. (incorporated by reference to Exhibit 2.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 filed by ConocoPhillips on May 4, 2017). |
| 2.3†‡ | Asset Purchase and Sale Agreement Amending Agreement, dated as of May 16, 2017, by and among ConocoPhillips Company, ConocoPhillips Canada Resources Corp., ConocoPhillips Canada Energy Partnership, ConocoPhillips Western Canada Partnership, ConocoPhillips Canada (BRC) Partnership, ConocoPhillips Canada E&P ULC, and Cenovus Energy Inc. (incorporated by reference to Exhibit 2.2 to the Current Report of ConocoPhillips on Form 8-K filed on May 18, 2017; File No. 001-32395). |
| 3.1 | Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395). |
| 3.2 | Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987). |
| 3.3 | Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of October 9, 2015 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on October 13, 2015; File No. 001-32395). |
| | ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request. |
| 10.1 | 1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.2 | 1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |

| Exhibit Number | Description |
|---|---|
| 10.3 | Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.4 | Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 001-00720). |
| 10.5 | Amendment and Restatement of ConocoPhillips Supplemental Executive Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.14 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.6 | Non-Employee Director Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.18 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.7 | Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.19 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.8 | Key Employee Missed Credited Service Retirement Plan of ConocoPhillips (incorporated by reference to Exhibit 10.10 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395). |
| 10.9 | Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.10.1 | Amendment and Restatement of ConocoPhillips Key Employee Supplemental Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.13 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.10.2 | First Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan, dated July 20, 2015 (incorporated by reference to Exhibit 10.10.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.10.3 | Second Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan, dated March 14, 2016 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395). |
| 10.11.1 | Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips—Title I, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.11.2 | Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.11.3 | First Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated October 11, 2012 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.11.4 | Second Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated December 17, 2015 (incorporated by reference to Exhibit 10.11.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.12 | 2002 Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.13 | Amendment and Restatement of 1998 Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.14 | Amendment and Restatement of 1998 Key Employee Stock Performance Plan of ConocoPhillips (incorporated by reference to Exhibit 10.28 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.15 | Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips (incorporated by reference to Exhibit 10.17 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395). |
| 10.16 | ConocoPhillips Form Indemnity Agreement with Directors (incorporated by reference to Exhibit 10.34 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.17.1 | Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of the Annual Report of ConocoPhillips Holding Company on Form 10-K for the year ended December 31, 1999; File No. 001-14521). |
| 10.17.2 | Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.17.3 | Phillips Petroleum Company Grantor Trust Agreement, dated June 1, 1998 (incorporated by reference to Exhibit 10.17.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.17.4 | First Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated May 3, 1999 (incorporated by reference to Exhibit 10.17.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.17.5 | Second Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated January 15, 2002 (incorporated by reference to Exhibit 10.17.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.17.6 | Third Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated October 5, 2006 (incorporated by reference to Exhibit 10.17.6 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.17.7 | Fourth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 1, 2012 (incorporated by reference to Exhibit 10.17.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.17.8 | Fifth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 20, 2015 (incorporated by reference to Exhibit 10.17.8 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.18.1 | ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10.40 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987). |
| 10.18.2 | First and Second Amendments to the ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395). |
| 10.19 | ConocoPhillips Matching Gift Plan for Directors and Executives (incorporated by reference to Exhibit 10.41 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987). |
| 10.20.1 | Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title I, dated April 19, 2012 (incorporated by reference to Exhibit 10.12.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.20.2 | Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, dated April 19, 2012 (incorporated by reference to Exhibit 10.12.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.20.3 | First Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips—Title II (incorporated by reference to Exhibit 10.20.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395). |
| 10.20.4 | Second Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips—Title II (incorporated by reference to Exhibit 10.20.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395). |
| 10.20.5 | Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, 2013 Restatement dated November 17, 2014 (Amended and Restated effective as of January 1, 2013) (incorporated by reference to Exhibit 10.20.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2014; File No. 001-32395). |
| 10.21 | Amendment and Restatement of ConocoPhillips Key Employee Change in Control Severance Plan, effective January 1, 2014 (incorporated by reference to Exhibit 10.21 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2013; File No. 001-32395). |

| Exhibit Number | Description |
| --- | --- |
| 10.22 | ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395). |
| 10.23.1 | 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix C of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2004 Annual Meeting of Shareholders; File No. 000-49987). |
| 10.23.2 | Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395). |
| 10.23.3 | Form of Performance Share Unit Award Agreement under the Performance Share Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395). |
| 10.24 | Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007 (incorporated by reference to Exhibit 10.30 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2007; File No. 001-32395). |
| 10.25 | 2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2009 Annual Meeting of Shareholders; File No. 001-32395). |
| 10.26.1 | 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2011 Annual Meeting of Shareholders; File No. 001-32395). |
| 10.26.2 | Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective February 9, 2012 (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2012; File No. 001-32395). |
| 10.26.3 | Form of Restricted Stock Units Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective April 4, 2012 (incorporated by reference to Exhibit 10.6 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.26.4 | Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective May 8, 2012 (incorporated by reference to Exhibit 10.7 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.26.5 | Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 18, 2012 (incorporated by reference to Exhibit 10.26.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.26.6 | Form of Performance Share Unit Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.6 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.7 | Form of Performance Share Unit Agreement—Canada under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.8 | Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.8 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.9 | Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.9 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.26.10 | Form of Make-up Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated January 1, 2012 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2013; File No. 001-32395). |
| 10.26.11 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.12 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.26.13 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Restricted Stock Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.14 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.14 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.26.15 | Form of Performance Period IX Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.26.16 | Form of Performance Period IX Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.4 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.17 | Form of Performance Period X Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.5 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.18 | Form of Performance Period X Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.6 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.19 | Form of Performance Period XII Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.20 | Form of Performance Period XII Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.21 | Form of Performance Period XIV Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.26.22 | Form of Performance Period XIV Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.24 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.26.23 | Form of Inducement Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated March 31, 2014 (incorporated by reference to Exhibit 10.11 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.26.24* | Form of Performance Share Unit Award Terms and Conditions for Performance Period 18, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018. |

| Exhibit Number | Description |
|---|---|
| 10.26.25* | Form of Performance Share Unit Award Terms and Conditions for Performance Period 18 for eligible employees on the Canada payroll, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018. |
| 10.27.1 | 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 14, 2014; File No. 001-32395). |
| 10.27.2 | Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program of ConocoPhillips, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 15, 2014 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2014; File No. 001-32395). |
| 10.27.3 | Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 3, 2015 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2015; File No. 001-32395). |
| 10.27.4 | Form of Retention Award Terms and Conditions, as part of the Restricted Stock Unit Award, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2015; File No. 001-32395). |
| 10.27.5 | Form of Non-Employee Director Restricted Stock Units Terms and Conditions, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395). |
| 10.27.6 | Form of Non-Employee Director Restricted Stock Units Terms and Conditions – Canadian Non-Employee Directors, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.4 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395). |
| 10.27.7 | Form of Non-Employee Director Restricted Stock Units Terms and Conditions – Norwegian Non-Employee Directors, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.5 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395). |
| 10.27.8 | Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Stock Option Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2017; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.27.9 | Form of Performance Share Unit Award Terms and Conditions for Performance Period 17, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2017; File No. 001-32395). |
| 10.27.10 | Form of Performance Share Unit Award Terms and Conditions for Performance Period 17 for eligible employees on the Canada payroll, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2017; File No. 001-32395). |
| 10.27.11 | Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017 (incorporated by reference to Exhibit 10.4 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2017; File No. 001-32395). |
| 10.27.12* | Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Executive Restricted Stock Unit Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018. |
| 10.27.13* | Form of Key Employee Award Terms and Conditions for eligible employees on the Canada payroll, as part of the ConocoPhillips Executive Restricted Stock Unit Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018. |
| 10.27.14* | Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018. |
| 10.27.15* | Form of Retention Award Terms and Conditions, 2017 revision, as part of the Restricted Stock Unit Award, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips. |
| 10.28 | Amendment and Restatement of Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips, dated April 19, 2012 (incorporated by reference to Exhibit 10.8 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.29 | Amendment, Change of Sponsorship, and Restatement of Certain Nonqualified Deferred Compensation Plans of ConocoPhillips, dated April 19, 2012 (incorporated by reference to Exhibit 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.30 | Amendment and Restatement of the Burlington Resources Inc. Management Supplemental Benefits Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |

| Exhibit Number | Description |
|---|---|
| 10.31 | Amendment and Restatement of Deferred Compensation Trust Agreement for Non-Employee Directors of Phillips Petroleum Company, dated June 23, 1995 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395). |
| 10.32 | Indemnification and Release Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.33 | Intellectual Property Assignment and License Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.2 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.34 | Tax Sharing Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.3 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.35 | Employee Matters Agreement between ConocoPhillips and Phillips 66, dated April 12, 2012 (incorporated by reference to Exhibit 10.4 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.36 | Transition Services Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.5 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.37 | ConocoPhillips Clawback Policy dated October 3, 2012 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395). |
| 10.38 | Term Loan Agreement, between ConocoPhillips, as borrower, ConocoPhillips Company, as guarantor, Toronto Dominion (Texas) LLC, as administrative agent and the banks party thereto, with TD Securities (USA) LLC, as lead arranger and bookrunner, dated March 18, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on March 21, 2016; File No. 001-32395). |
| 12* | Computation of Ratio of Earnings to Fixed Charges. |
| 21* | List of Subsidiaries of ConocoPhillips. |
| 23.1* | Consent of Ernst & Young LLP. |
| 23.2* | Consent of DeGolyer and MacNaughton. |
| 31.1* | Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934. |
| 31.2* | Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934. |
| 32* | Certifications pursuant to 18 U.S.C. Section 1350. |
| 99* | Report of DeGolyer and MacNaughton. |

| Exhibit Number | Description |
| --- | --- |
| 101.INS* | XBRL Instance Document. |
| 101.SCH* | XBRL Schema Document. |
| 101.CAL* | XBRL Calculation Linkbase Document. |
| 101.DEF* | XBRL Definition Linkbase Document. |
| 101.LAB* | XBRL Labels Linkbase Document. |
| 101.PRE* | XBRL Presentation Linkbase Document. |

* *Filed herewith.*

† *The schedules to this exhibit have been omitted pursuant to Item 601(b)(2) of Regulation S-K. ConocoPhillips agrees to furnish a copy of any schedule omitted from this exhibit to the SEC upon request.*

‡ *ConocoPhillips has previously been granted confidential treatment for certain portions of this exhibit pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended.*

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

**CONOCOPHILLIPS**

| | |
|---|---|
| February 20, 2018 | */s/ Ryan M. Lance*<br>Ryan M. Lance<br>Chairman of the Board of Directors<br>and Chief Executive Officer |

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 20, 2018, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

| Signature | Title |
|---|---|
| */s/ Ryan M. Lance*<br>Ryan M. Lance | Chairman of the Board of Directors<br>and Chief Executive Officer<br>(Principal executive officer) |
| */s/ Don E. Wallette, Jr.*<br>Don E. Wallette, Jr. | Executive Vice President, Finance,<br>Commercial and Chief Financial Officer<br>(Principal financial officer) |
| */s/ Glenda M. Schwarz*<br>Glenda M. Schwarz | Vice President and Controller<br>(Principal accounting officer) |

| | |
|---|---|
| */s/ Richard L. Armitage*<br>Richard L. Armitage | Director |
| */s/ Richard H. Auchinleck*<br>Richard H. Auchinleck | Director |
| */s/ Charles E. Bunch*<br>Charles E. Bunch | Director |
| */s/ Caroline M. Devine*<br>Caroline M. Devine | Director |
| */s/ Gay Huey Evans*<br>Gay Huey Evans | Director |
| */s/ John V. Faraci*<br>John V. Faraci | Director |
| */s/ Jody Freeman*<br>Jody Freeman | Director |
| */s/ Sharmila Mulligan*<br>Sharmila Mulligan | Director |
| */s/ Arjun N. Murti*<br>Arjun N. Murti | Director |
| */s/ Robert A. Niblock*<br>Robert A. Niblock | Director |
| */s/ Harald J. Norvik*<br>Harald J. Norvik | Director |

## Board of Directors

(As of Feb. 20, 2018)

**Richard L. Armitage**
President, Armitage International LLC,
Former U.S. Deputy Secretary of State

**Richard H. Auchinleck**
Former President and Chief Executive Officer, Gulf Canada Resources Limited

**Charles E. Bunch**
Former Chairman and Chief Executive Officer, PPG Industries, Inc.

**Caroline Maury Devine**
Former President and Managing Director of a Norwegian affiliate of ExxonMobil

**John V. Faraci**
Former Chairman and Chief Executive Officer, International Paper Company

**Jody Freeman**
Archibald Cox Professor of Law,
Harvard Law School

**Gay Huey Evans, OBE**
Deputy Chairman,
Financial Reporting Council

**Ryan M. Lance**
Chairman and Chief Executive Officer,
ConocoPhillips

**Sharmila Mulligan**
Founder and Chief Executive Officer,
ClearStory Data Inc.

**Arjun N. Murti**
Senior Advisor, Warburg Pincus

**Robert A. Niblock**
Chairman, President and Chief Executive Officer, Lowe's Companies, Inc.

**Harald J. Norvik**
Former Chairman, President and Chief Executive Officer, Statoil

## Executive Leadership Team

(As of Feb. 20, 2018)

**Ryan M. Lance**
Chairman and Chief Executive Officer

**Matt J. Fox**
Executive Vice President, Strategy, Exploration and Technology

**Al J. Hirshberg**
Executive Vice President, Production, Drilling and Projects

**Don E. Wallette, Jr.**
Executive Vice President, Finance, Commercial and Chief Financial Officer

**Janet Langford Carrig**
Senior Vice President, Legal, General Counsel and Corporate Secretary

**Andrew D. Lundquist**
Senior Vice President, Government Affairs

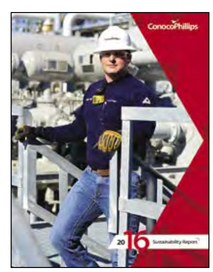
**Ellen R. DeSanctis**
Vice President, Investor Relations and Communications

**James D. McMorran**
Vice President, Human Resources and Real Estate and Facilities Services

## Explore ConocoPhillips

**Fact Sheets**
The ConocoPhillips fact sheets provide detailed operational updates for each of the company's six segments. The fact sheets are updated annually and are available at *www.conocophillips.com/factsheets*.

**Sustainability Report**
The ConocoPhillips Sustainability Report provides an overview of the company's sustainable development programs and metrics. The 2017 Sustainability Report will be available in June at *www.conocophillips.com/sustainability*.



Certain disclosures in this annual report may be considered "forward-looking" statements. These are made pursuant to "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The "Cautionary Statement" in the Management's Discussion and Analysis in ConocoPhillips' 2017 Form 10-K should be read in conjunction with such statements.

"ConocoPhillips," "the company," "we," "us" and "our" are used interchangeably in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries.

ConocoPhillips

www.facebook.com/conocophillips

www.youtube.com/user/conocophillips

www.linkedin.com/company/conocophillips

www.instagram.com/conocophillips

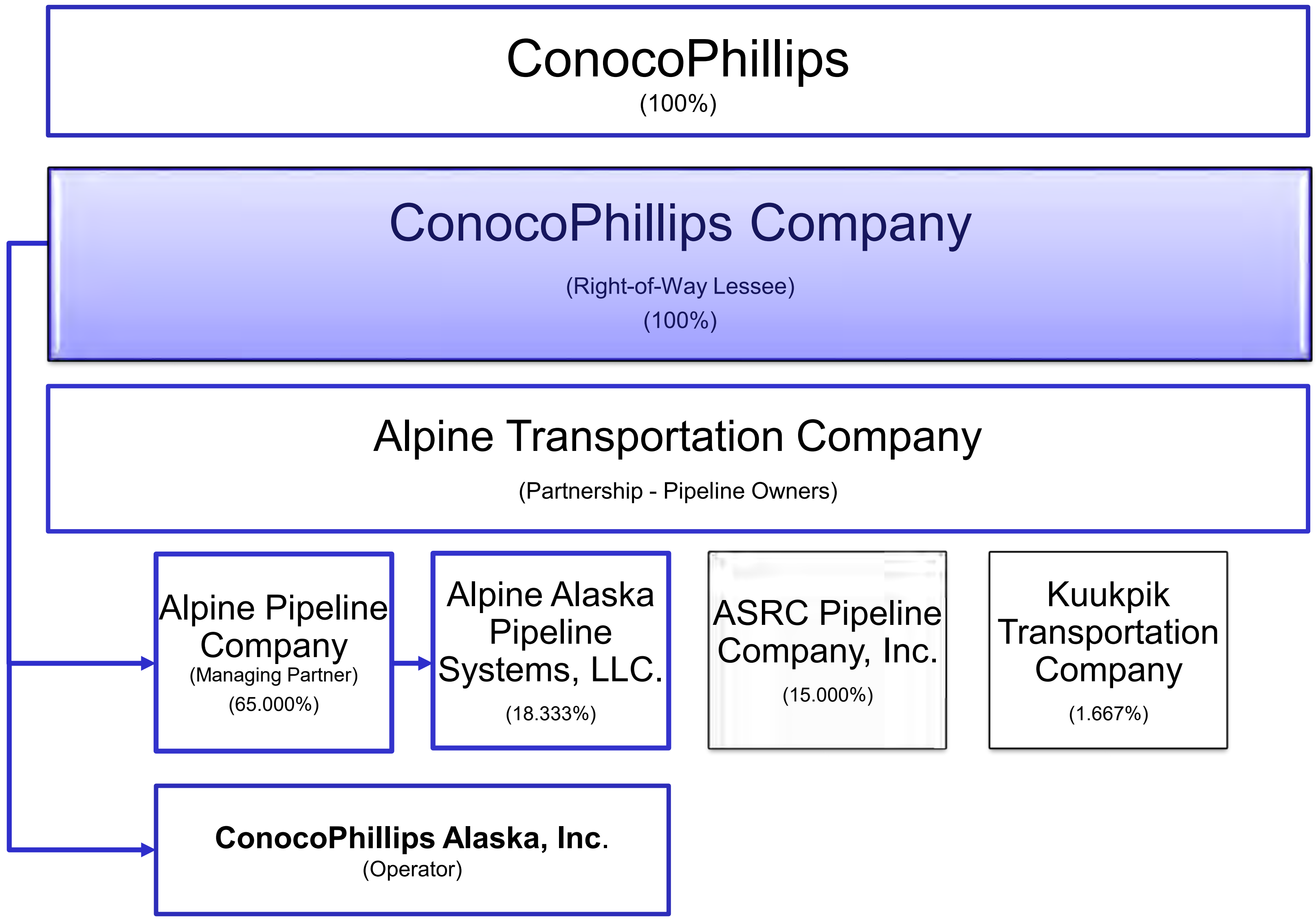
@conocophillips

# ATTACHMENT 1

a. Commercial Business License
b. Certificate of Good Standing/Compliance from the Division of Corporations
c. Annual Financial Statement and Balance Sheets 2015-2017
d. **Ownership Interest Diagram**

# Alpine Oil Pipeline

## OWNERSHIP INTEREST



# Alpine Diesel & Utility Pipelines

## OWNERSHIP INTEREST

**ConocoPhillips**
(100%)

↓

**ConocoPhillips Company**
(Rights-of-Way Lessee)
(Wholly Owned Subsidiary)

↓

**ConocoPhillips Alaska, Inc.**
(Pipelines Owner and Operator)
(Wholly Owned Subsidiary)

# ATTACHMENT 2

a. Statement of full compliance to regulation and taxation of the pipeline facility
b. Statement of full compliance with all terms of the lease
c. Statement of full compliance with other state, borough or federal regulations and authorizations

# ATTACHMENT 2

a. **Statement of full compliance to regulation and taxation of the pipeline facility**
b. **Statement of full compliance with all terms of the lease**
c. **Statement of full compliance with other state, borough or federal regulations and authorizations**

# Alpine Pipelines Statement of Compliance

ConocoPhillips Company (CPC), Right-of-Way Lessee, and ConocoPhillips Alaska, Inc. (CPAI) as Operator of the Alpine Pipelines are wholly owned subsidiaries of ConocoPhillips.

CPC and CPAI ensure compliance with state laws and regulations through the following:

- Instituting corporate processes
- Applying business unit systems and processes
- Employing and training knowledgeable personnel
- Regularly evaluating policies, systems, and processes to ensure compliance with federal, state and local laws
- Properly addressing and resolving any non-compliances discovered

**Instituting Corporate Processes**

ConocoPhillips Company implements a Health, Safety and Environment Management System Standard (HSEMSS) that is an integral part of the total business process. Management's commitment and leadership are the principal elements of the HSEMSS and are critical to its success. The HSEMSS structure consists of 15 elements which, when properly executed, lead to exceptional environmental, health, and safety performance.

Strategic planning establishes and defines the goals which are to be achieved and provides a focus towards the desired results. Strategic planning integrates assessments into the overall business plan. The strategic plan is executed through defined tactics and implementing specific actions or objectives and following well-defined procedures to achieve goals. Performance indicators combine both pro-active and re-active measurements. The system measures the achievement of plans and the extent of compliance with rules, regulations, permits, and standards. Regulatory assessment and advocacy require a system to monitor proposed and final regulations to ensure timely, cost-effective evaluation and implementation of alternatives for achieving compliance.

Alliances with government policy makers, interested citizens, and business groups have been built to develop sound laws, regulations, and policies promoting the common objectives of safe working conditions, environmental protection, and economic development.

Audits provide assessments of the total system, supplying the feedback necessary to enable the organization to maintain and develop its ability to properly manage risks and to identify areas for improvement. Finally, reviews of the entire HSEMSS, including its elements and performance, allows for a continuous improvement cycle.

**Applying Systems and Processes**

ConocoPhillips Company and its subsidiaries have programs, systems, and processes in place to ensure compliance with all applicable laws and regulations. These programs, systems, and processes consist of the following:

- Various Quality Assurance Systems including the Quality Management System
- Surveillance and Monitoring Program
- Compliance Tool developed specifically to address compliance with the ROW lease, its stipulations and commitments, in addition to Federal regulation, as applicable
- Annual Reports to the State Pipeline Coordinator's Section
- CPAI managed Maintenance Program
- Environmental Permit Compliance System to ensure State, Federal and Local permits are secured prior to the start of work, as applicable

A combination of these systems and processes ensures compliance with all state, federal and local laws and regulations.

**Employing and Training Knowledgeable Personnel**

Employees receive training to ensure competency when accomplishing their assigned roles and responsibilities. Training systems provide initial, periodic, and on-going training based on job needs. Performance criteria, measured against clearly defined objectives, ensure the effectiveness of instructors and training systems.

**Regularly Evaluating Policies, Systems, and Processes to Ensure Compliance**

Part of the corporate HSEMSS process is a periodic review of the program, 15 elements, and performance. Audits are an integral part of the review process, providing valuable feedback on whether policies, systems, and processes work well or need improvement. Both internal and external audits are conducted continuously throughout the company to identify deficiencies within the established policies, systems, and processes.

**Properly Addressing and Resolving Discovered Non-Compliance Issues**

Once deficiencies are identified either through an audit, assessment or other process, corrective action is initiated to address the deficiency. Corrective action varies depending on the identified deficiency and the management program involved. Corrective actions may include process modifications, policy updates, incorporation of new regulations and guidelines into programs, or training. Proper documentation of all corrective actions is mandatory. Additionally, state and federal agencies independently oversee compliance on behalf of the public, thereby providing further assurance of compliance.

**Lessee's Full Compliance Statement**

ConocoPhillips Company pipeline systems and processes are effective in maintaining compliance with state requirements, as demonstrated by both internal and external independent reviews, as well as consistent oversight of operations by State and Federal agencies. ConocoPhillips Company has met all compliance requirements for renewing the ROW leases.

# Regulation of Taxation

**<u>Lessee's State Tax Compliance Statement</u>**

ConocoPhillips Company is current in all tax filings required under the laws of the State of Alaska, pertaining to the Alpine Pipelines as defined in the ROW Leases ADL 415932, 415701 and 415857, Condition 17, executed on December 15, 1998 and on January 6, 1999.

# ATTACHMENT 3

a. Pipeline Characteristics and Description
b. Discussion of Useful Life, Design Life, Physical Life and Economic Life
c. Condition of the Right-of-Way
d. Corrected Record of Survey, dated February 9, 2011, No. EPF20020040A

# ATTACHMENT 3

a. **Pipeline Characteristics and Description**
b. **Discussion of Useful Life, Design Life, Physical Life and Economic Life**
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# Alpine Pipelines Characteristics

**Alpine Oil Pipeline**

The DOT-regulated Alpine Oil Pipeline (AOP) transports processed crude oil from the Colville River Unit (CRU) Alpine Central Facility (ACF) eastward to a connection with the Kuparuk Pipeline (KPL) system at Central Processing Facility 1 (CPF-1) for continued transport to the Trans Alaska Pipeline System (TAPS) Pump Station 1 (PS1)

**Alpine Diesel Pipeline**

The DOT-regulated Alpine Diesel Pipeline (ADP) transports diesel or mineral oil in batches from the Kuparuk River Unit (KRU) westward to Alpine Central Processing Facility 1 (ACPF-1) located in the Colville River Unit for the purpose of transporting products necessary for drilling and production activities at Alpine.

**Alpine Utility Pipeline**

The Alpine Utility Pipeline (AUP) transports Seawater from Kuparuk CPF2 to ACF for water flood support. Placed in temporary natural gas service on 21 June 2000, it was converted to seawater service on 22 January 2001. The Pipeline is not DOT regulated; however, AUP owners and operators have voluntarily agreed to operate and maintain the SWPL in compliance with many of the Federal regulations in 49 CFR Part 195 "Transportation of Hazardous Liquids by Pipeline".

The pipelines are routed mostly aboveground, supported by a system of horizontal beams (HSMs) and vertical support members (VSMs). The aboveground portion of the pipelines is uncoated and insulated with 3 inches of shop-applied polyurethane protected by a galvanized steel jacket.

All three pipelines cross the Colville, Kachemach, and Miluveach Rivers. The Kachemach and Miluveach are shallow and narrow, and the pipelines cross both on the aboveground support system. At the Colville River, the pipelines transition into individual cased below-grade crossings. Horizontal Directional Drilling (HDD) was used to install approximately casing below the river at approximately 80' below the riverbed. The below-grade casings and pipelines are FBE coated. Isolator assemblies clamped to the pipelines prevent contact between the pipe and casing. The pipelines are protected against corrosion by its external coating and the casing. The casings are protected against corrosion by external coating and a cathodic protection system. A dedicated leak detection system monitors for both leakage of product into casings, and water into casings from outside.

There are no isolation valves at the river crossings. Vertical loops are used in place of valves to more-effectively minimize leak volumes. Actuated valves at the inlet and outlet isolate and depressure the pipelines, creating a closed system with no way for a syphon to develop.

Attached is the *Corrected Record of Survey*, dated February 9, 2011, No. EPF20020040A which shows the center of alignment for each pipeline's operational ROW boundary over State Lands.

## Alpine Pipelines Description

**Alpine Oil Pipeline**

Constructed between 1999 and 2000 and commissioned in November 2000. The 14-inch pipeline transports a maximum of 145,000 standard barrels of crude oil per day from the Alpine field. The hydraulic limit of the pipeline system based on a surge analysis is 190,000 barrels per day. There are no pumping, heating, refrigeration, or compressing stations located within the Alpine Oil Pipeline ROW.

**Alpine Diesel Pipeline**

Constructed in 1998 and commissioned in May 1999, the 2.375-inch pipeline can transport a maximum of 15 gallons of product[1] per minute (gpm) at temperatures up to 100F from KRU to CRU. Metering, pigging, pumping, and tank facilities are located at CPF2.

**Alpine Utility Pipeline**

Constructed in 1999 and commissioned in November 2000 to transport natural gas, the pipeline was converted the following year to transport treated seawater from CPF2 to CRU. The 12-inch pipeline under seawater service is designed to flow a maximum of 70,000 barrels of seawater at a temperature of 150F. The pipeline is hydraulically limited to 107,000 barrels per day based on its surge analysis.

**Useful Life**

The useful life of the Alpine Pipelines is the period during which an economic benefit can be derived from continuing operations and maintenance of the pipeline systems, and they can continue to operate safely and without harm to the environment. Useful life of the pipelines is a combination of design life, physical life, and economic life.

**Design Life**

The pipelines are designed to function reliably and safely, and with structural integrity to resist arctic operating conditions while protecting the environment. Pipeline operations have been stable since commissioning. Programs such as the surveillance and monitoring program and Quality Assurance Program ensure the viability and functioning of the pipeline systems and gauge the status of the pipeline systems against the original design standards.

**Surveillance and Monitoring Program**

The surveillance and monitoring program is intended to ensure public health and safety, control damage to natural resources and public and private property, mitigate erosion, and maintain pipeline integrity. The aboveground pipelines and mainline valves are routinely inspected for leaks and spills; vertical support member jacking, settlement and tilt; broken, damaged or skewed saddles; and general pipeline damage. The monitoring program consists of identifying both internal and external corrosion and pipeline vibration. Periodic aerial and ground-based surveillance is performed when accessible and visual observations are made to detect pipeline integrity issues, or that may endanger the health and safety of people or cause environmental harm (including adverse effects on fish and wildlife) and ensure compliance with applicable ROW lease requirements.

[1] The ADP currently transports only ultra-low sulfur diesel or mineral oil.

**Quality Assurance Program**

The quality program ensures pipeline system operations within established parameters, an essential element of risk management. This requires procedures, structured inspection and maintenance systems, reliable safety systems and control devices, clean facilities, and qualified personnel who execute these procedures and practices consistently. Quality program components ensure:

- Management provides the vision, sets the expectations, and provides the resources for implementation of the program, which requires understanding, active involvement, and commitment by all employees.
- Comprehensive risk management reduces operating risk and the potential for safety, health, and environmental incidents and liabilities.
- Careful selection, placement, training, development, and assessment of employees.
- Use of accepted standards, procedures, and specifications for facility design, construction, and startup activities.
- Facilities operation within established parameters, which requires operation, inspection, and maintenance procedures, and information on the process, facilities, and materials handled.
- Evaluation and management of risk associated with changes in organization, operations, procedures, design criteria, facilities, regulatory or permit requirements.
- Third parties who provide materials and services (personnel and equipment) or operate facilities on behalf of APC, do so in a manner that is consistent with applicable policies and business objectives.
- Reporting, investigation, and follow-up of incidents and near miss events.
- Protection of employees, third parties, the public, the environment and assets in the event of an incident through emergency planning and preparedness exercises.
- An assessment process is in-place to assess performance relative to the quality plan expectations and to promote improvement.

**Physical Life**

As referenced in the *Duration for the Right-of-Way Renewal for the Trans Alaska Pipeline System* (submitted to the Department of Natural Resources as part of the TAPS ROW renewal project), studies of other pipelines, including Alaska pipelines, confirm that, given appropriate vigilance and maintenance, age does not increase risks to pipeline integrity. A study of Cook Inlet oil pipelines by the Alaska Department of Environmental Conservation concluded that age had little to do with pipeline integrity – what mattered was maintenance and how operating conditions compared with the design conditions. According to the study, pipelines could last multiples of their design life with proper maintenance (Visser, et. al., 1993)[2].

Each pipeline's physical life is dependent on pipeline system integrity assured by implementing proactive maintenance programs that promote continued safe and environmentally sound transport of product. Alpine maintenance programs ensure pipeline integrity through the use of smart pigs for AOP and AUP, hydrostatic testing of ADP, periodic testing of existing corrosion protection systems, and visual inspections. Maintenance and repair programs keep the pipeline in a safe, reliable state that protects the surrounding environment from adverse impacts of pipeline operations.

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[2] Visser, R. C., F. C. Duthweiler, and H. B. Carlile. 1993. Oil Pipeline Risk Assessment - Cook Inlet, Alaska. Prepared by Belmar Management Services for Alaska Department of Environmental Conservations. November 1993.

The initial, comprehensive programs to detect and repair potential problems that might threaten pipeline system integrity have been constantly improved and expanded. Industry-accepted methods have been employed to monitor the condition of the pipeline and associated facilities. These programs verify that the initial design specifications and construction methods were robust and lasting even in harsh arctic conditions. The surveillance and monitoring, quality, and maintenance and repair programs, combined with the robust design of the pipeline, result in a pipeline system with an essentially unlimited life.

**Economic Life**

The economic life of the pipelines is largely a function of the economic life of the Alpine field and fields within the National Petroleum Reserve Alaska (NPRA), including the future developments of Greater Moose's Tooth 1 (GMT1), Greater Moose's Tooth 2 (GMT2), and potentially the Willow project. Since the AUP and ADP are utilized in support of oil production, as long as the enduring costs of extracting and transporting crude oil from each of the fields are less than the financial benefits of selling oil, the field and all three pipelines remain feasible.

Economic life also depends upon a number of factors, including pipeline and marine transportation costs, and the market price of oil. As in the case of predictions of oil recoveries from the existing oil reserves, constant technological innovation and improvements in efficiency have led to the discovery of additional reserves and sustained oil production capacity that exceed original projections. With advancements in technology and operations techniques, the oil reservoirs will continue to produce. Examples of new technology that expand the useful life of oil development include: enhanced directional drilling that allows existing facilities to drill longer distances into reservoirs, and gas cap water injection designed to mitigate the pressure decline and improve hydrocarbon liquid recovery from a reservoir.

Long-term estimates of economically recoverable oil production depend on many variables. There is every reason to believe that with the past trends, increased reserves, and technological and efficiency improvements, the economic life of each of the Alpine Pipelines will extend beyond 30 years.

**Rights-of-Way Condition Statement**

ConocoPhillips Company pipeline's monitoring, and inspection programs are effective in ensuring the public's health and safety; controls damage to natural resources, public and private property, mitigates erosion, and assures the integrity of each pipeline system. ConocoPhillips Company meets the compliance requirements for renewing the ROW leases.

# ATTACHMENT 3

a. Pipeline Characteristics and Description
b. Discussion of Useful Life, Design Life, Physical Life and Economic Life
c. Condition of the Right-of-Way
d. **Corrected Record of Survey, dated February 9, 2011, No. EPF20020040A**


## PARCEL AREA TABLE

| | | SQ.FT. | ACRES |
|---|---|---|---|
| PARCEL 1 | ADL 415701 | 712,302 | 16.35 |
| | ADL 415857 | 711,215 | 16.33 |
| | ADL 415932 | 709,728 | 16.29 |
| | | SQ.FT. | ACRES |
| PARCEL 2 | ADL 415701 | 28,363 | 0.65 |
| | ADL 415857 | 28,062 | 0.64 |
| | ADL 415932 | 27,956 | 0.64 |
| | | SQ.FT. | ACRES |
| PARCEL 3 | ADL 415701 | 178,323 | 4.09 |
| | ADL 415857 | 178,258 | 4.09 |
| | ADL 415932 | 177,735 | 4.08 |
| | | SQ.FT. | ACRES |
| PARCEL 4 | ADL 415701 | 5,553,954 | 127.50 |
| | ADL 415857 | 5,554,153 | 127.51 |
| | ADL 415932 | 5,551,103 | 127.44 |

## TOTAL LENGTH OF EACH LINE

| | | FEET |
|---|---|---|
| PARCEL 1 | ADL 415701 | 14,276.43 |
| | ADL 415857 | 14,252.28 |
| | ADL 415932 | 14,218.74 |
| PARCEL 2 | ADL 415701 | 567.26 |
| | ADL 415857 | 561.25 |
| | ADL 415932 | 559.13 |
| PARCEL 3 | ADL 415701 | 3,564.62 |
| | ADL 415857 | 3,564.80 |
| | ADL 415932 | 3,543.75 |
| PARCEL 4 | ADL 415701 | 109,867.44 |
| | ADL 415857 | 109,879.58 |
| | ADL 415932 | 109,738.43 |

## NOTES

1. THIS SURVEY WAS ACCOMPLISHED IN ACCORDANCE WITH AS 38.05.850 AND SI No. 2002-40.
2. THE BEARINGS AS SHOWN ARE STATE PLANE GRID BEARINGS AS ORIENTED TO THE BASIS OF BEARINGS AND DISTANCES SHOWN ARE REDUCED TO HORIZONTAL GRID DISTANCES, UNLESS OTHERWISE NOTED.
3. THE ERROR OF CLOSURE OF THIS SURVEY IS NOT GREATER THAN 1:5000.
4. ALL PARCELS OF LAND OWNED BY THE STATE OF ALASKA, LOCATED WITHIN 50.00 FEET OF A SURVEYED OR PROTRACTED SECTION LINE, ARE SUBJECT TO A 50 FOOT (50') EASEMENT, EACH SIDE OF THE SECTION LINE, WHICH IS RESERVED TO THE STATE OF ALASKA FOR PUBLIC HIGHWAYS UNDER A.S. 19.10.010 UNLESS OTHERWISE VACATED OR NOTED ON THE PLAT.
5. THIS SURVEY DOES NOT CONSTITUTE A SUBDIVISION AS DEFINED BY AS 29.71.800 OR AS 40.15.900.
6. THERE IS HEREBY RESERVED A PUBLIC ACCESS EASEMENT 50 FEET WIDE, ALONG THE ORDINARY OR MEAN HIGH WATER LINE OF THE NAVIGABLE OR PUBLIC WATER BODIES WITHIN THIS SURVEY PURSUANT TO A.S. 38.05.127 (a).
7. HYDROLOGY SHOWN IS PER U.S.G.S. DATA.
8. LATITUDE AND LONGITUDE ARE N.A.D. 27.
9. ALL COORDINATES SHOWN ARE ALASKA STATE PLANE ZONE 4.
10. ALL SECTION LINES ARE PROTRACTED UNLESS OTHERWISE NOTED.
11. MEAN SCALE FACTOR IS 0.99990397.
12. THESE LEASES DO NOT, IN ANY WAY, RESTRICT ACCESS TO, ALONG, OR ACROSS THE DESCRIBED LANDS BY THE PUBLIC.

## LEGEND

FOUND STANDARD BLM 3 1/4" BRASS CAP ON 2 1/2" IRON POST

SET 3 1/4" ALUMINUM CAP ON 5/8" X 30" ALUMINUM POST

(2390.52') RECORD INFORMATION PER BLM U.S. TOWNSHIP PLAT

5211.02'(P) PRORATED INFORMATION

50' WIDE ADL 415701
14"ø CRUDE OIL LINE

50' WIDE ADL 415857
12"ø SEAWATER LINE

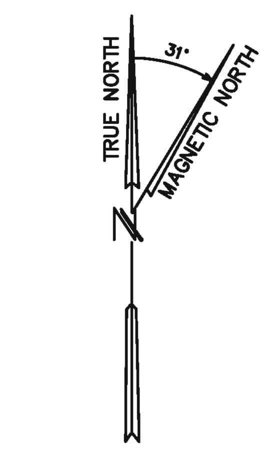
50' WIDE ADL 415932
2"ø DIESEL LINE

VSM 0122 VSM

VSM 0101A VSM ANCHOR

## REVISION TABLE

| NO. | DESCRIPTION | DATE |
|---|---|---|
| 1 | PAGE 1 MOVED PARCEL AREA TABLE AND TOTAL LENGTH OF EACH LINE TABLE. | 5/25/10 |
| 2 | PAGE 1 ADDED REVISION TABLE. | 5/25/10 |
| 3 | PAGE 1 ADDED NOTE ABOVE TITLE BLOCK. | 5/25/10 |
| 4 | PAGE 1 OBTAINED NEW APPROVAL SIGNATURES. | 5/25/10 |
| 5 | PAGE 1 TITLE BLOCK REVISED NAME FROM RECORD OF SURVEY TO CORRECTED RECORD OF SURVEY. | 5/25/10 |
| 6 | PAGE 1 PARCEL 1 ADL 415701, SQ. FT. REVISED FROM 715,424 TO 712,302, ACRES REVISED FROM 16.42 TO 16.35, FEET REVISED FROM 14,307.94 TO 14,276.43. PAGE 1 PARCEL 1 ADL 415857, SQ. FT. REVISED FROM 714,800 TO 711,215, ACRES REVISED FROM 16.41 TO 16.33, FEET REVISED FROM 14,300.96 TO 14,252.28. PAGE 1 PARCEL 1 ADL 415932, SQ. FT. REVISED FROM 712,284 TO 709,728, ACRES REVISED FROM 16.35 TO 16.29, FEET REVISED FROM 14,248.17 TO 14,218.74. PAGE 1 PARCEL 4 ADL 415932 REVISED ACREAGE FROM 107.44 TO 127.44. | 5/25/10 |
| 7 | PAGE 2 DETAIL CORRECTED TIE TO SEGMENT 1 POINT OF BEGINNING. | 5/25/10 |
| 8 | PAGE 4 MOVED P.O.B. POSITION TO THE CORRECT LOCATION WHICH IS WHERE THE LINES EXIT THE ALPINE PRODUCTION FACILITY (CFA2). | 5/25/10 |
| 9 | PAGE 4, PI ID TABLE, REMOVED DATA FOR PI A2C1, PI A2C2, PI A2C4, PI A2C5, PI A2S1, PI A2D1. ADDED DATA FOR P.O.B. | 5/25/10 |
| 10 | PAGE 4 ENLARGED DIAGRAM –A2 MODULE AND MAIN GRAPHIC – REMOVED FOLLOWING TEXT FROM WITHIN CFA2: PI–A2C2, PI–A2C1, ℄ 14" CRUDE OIL, PI–A2S1, ℄ 12" SEAWATER, PI–A2C5, P1–A2C4, PI–A2D1, ℄ 2" DIESEL. REMOVED LINES FROM WITHIN CFA2 AND CORRESPONDING EASEMENT LINES. | 5/25/10 |
| 11 | PAGE 4 EXTENDED 3 EASEMENT LINES TO SOUTH LINE OF CFA2. | 5/25/10 |
| 12 | PAGE 4 ADDED P.O.B. SYMBOL CONNECTING LINE AND BEARING/DISTANCE. | 5/25/10 |
| 13 | PAGE 5 REMOVED "SEGMENT 1 POINT OF BEGINNING" AND DETAIL DIAGRAM. | 5/25/10 |
| 14 | TITLE BLOCK ON ALL PAGES REVISED TOTAL AREA FROM 432 TO 446 ACRES MORE OR LESS. | 5/25/10 |
| 15 | TITLE BLOCK ON ALL PAGES ADDED SEC. 32, T. 12N, R. 5E. | 5/25/10 |
| 16 | TITLE BLOCK ON ALL PAGES CHANGED FILE NUMBER TO EPF20020040A. | 5/25/10 |




MEAN MAGNETIC DECLINATION
SOURCE: U.S.G.S. QUAD MAP HARRISON BAY (B-2) 1955

# INDEX SHEET

SCALE

0 1/2 1 2 3 4 MILES
0 1 2 3 4 5 6 KILOMETERS

ATTENTION IS CALLED TO THE FACT THAT THIS RECORD OF SURVEY WAS ORIGINALLY FILED FOR RECORD AS PLAT 2004–9 OF THE BARROW RECORDING DISTRICT. THE REVISION TABLE ON PAGE 1 OUTLINES ITEMS THAT WERE FOUND TO BE INCORRECT AND HAVE BEEN CORRECTED HEREON. THESE REVISIONS CONSTITUTE THE SOLE CHANGES MADE TO THE PLAT.
THE ABOVE REVISIONS DO NOT INFLUENCE ANY CHANGE OF OWNERSHIP, RIGHTS–OF–WAY, OR ANY OTHER ITEM WHICH WOULD ADVERSELY AFFECT THIS OR ADJACENT PROPERTIES. ANY DISCREPANCIES BETWEEN THIS CORRECTED RECORD OF SURVEY AND THE ORIGINAL AS FILED OTHER THAN THOSE LISTED IN THE REVISION TABLE WILL BE CONTROLLED BY THE ORIGINAL DOCUMENT (BARROW RECORDING DISTRICT 2004–9).

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

## APPROVAL CERTIFICATE

THIS PLAT HAS BEEN REVIEWED AND FOUND TO BE IN COMPLIANCE WITH APPLICABLE PROVISIONS OF LAW AND IS HEREBY APPROVED.

DATE

DIRECTOR, DIVISION OF MINING, LAND & WATER


## SURVEYOR'S CERTIFICATE

I HEREBY CERTIFY THAT I AM PROPERLY REGISTERED AND LICENSED TO PRACTICE LAND SURVEYING IN THE STATE OF ALASKA, THAT THIS PLAT REPRESENTS A SURVEY MADE BY ME OR UNDER MY DIRECT SUPERVISION, THAT THE MONUMENTS SHOWN HEREON ACTUALLY EXIST AS DESCRIBED, AND THAT ALL DIMENSIONS AND OTHER DETAILS ARE CORRECT.

DATE

LS 6923
REGISTRATION NUMBER

DEREK W. HOWARD
REGISTERED LAND SURVEYOR

DATE OF SURVEY
Beginning 3/01/01
Ending 4/12/01

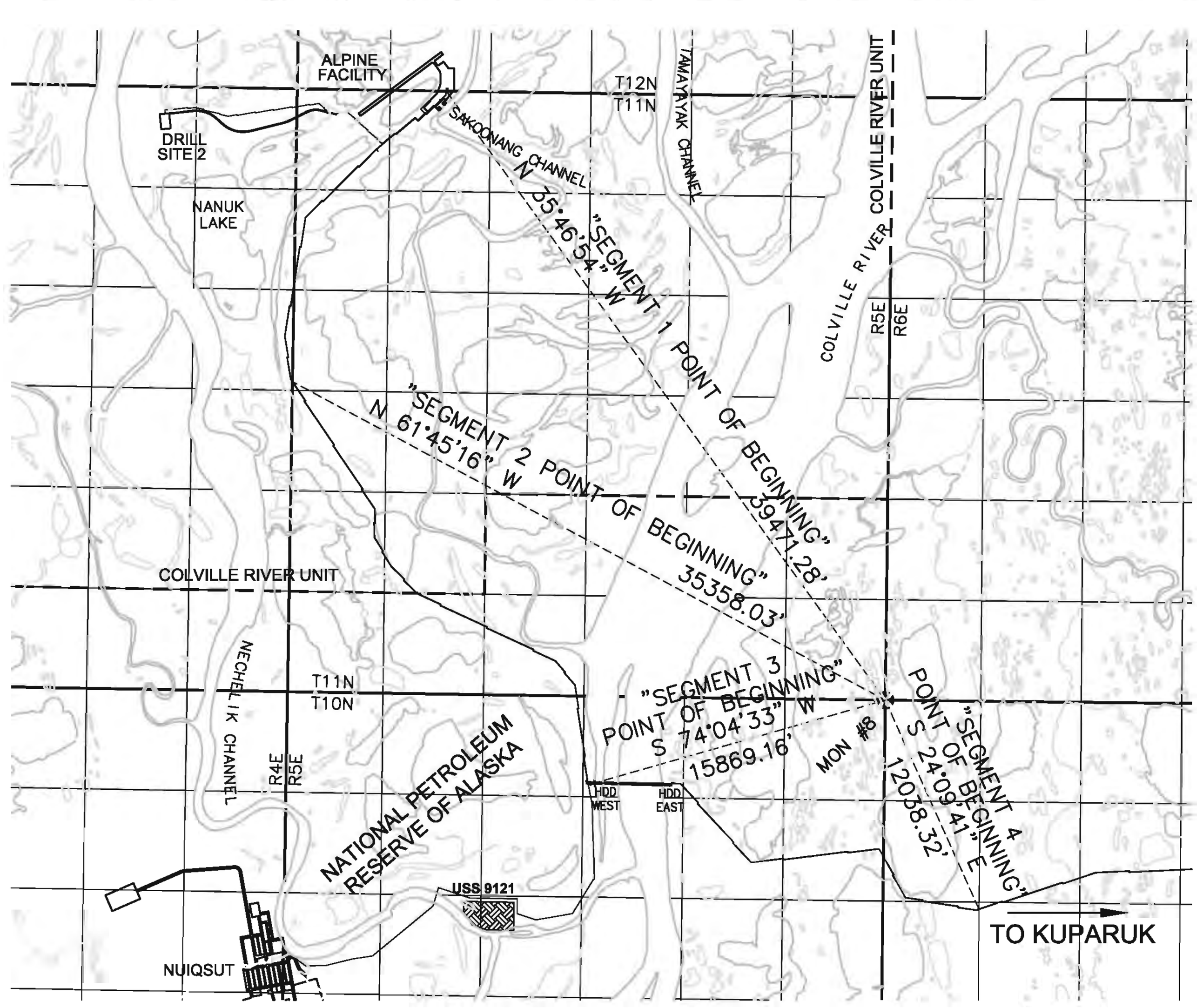
NAME OF SURVEYOR
LCMF Incorporated
139 E. 51St.
Anch., Alaska 99503

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

CORRECTED RECORD OF SURVEY
OF THE ALPINE TO KUPARUK CPF–2 OVERLAND PIPELINE
LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

| DRAWN BY CEZ<br>DATE 5/14/03 | APPROVAL RECOMMENDED<br>Statewide Platting Supervisor / Date | | |
|---|---|---|---|
| SCALE 1" = 1 MILE | CHECKED APH | SHEET 1 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |

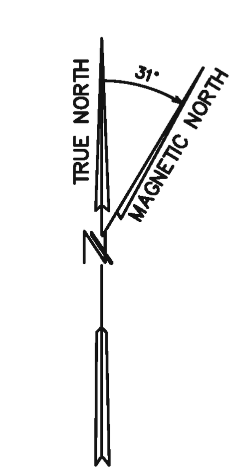

STATE OF ALASKA LANDS – SEGMENTS 1-4 POINT OF BEGINNING
1" = 8000'

## OWNERSHIP LEGEND

- STATE OF ALASKA
- IC 109 (KUUKPIK CORPORATION)
- IC 1568 (KUUKPIK CORPORATION)
- IC 568 (KUUKPIK CORPORATION)
- IC 620 (KUUKPIK CORPORATION)
- IC 628 (KUUKPIK CORPORATION)

## NOTES

1. FOR MORE DETAIL ON TOWNSHIP CROSSING INFORMATION, SEE SHEETS 5, 6, 9, 11, 13 AND 16.




MEAN MAGNETIC DECLINATION
SOURCE: U.S.G.S. QUAD MAP HARRISON BAY (B-2) 1955

SCALE
0 1/2 1 2 3 4 MILES
0 1 2 3 4 5 6 KILOMETERS

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

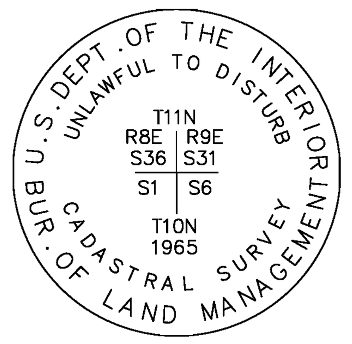
| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01 | LCMF Incorporated |
| Ending 4/12/01 | 139 E. 51St. Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

RECORD OF SURVEY
OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE
LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.;
SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.;
SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.;
SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

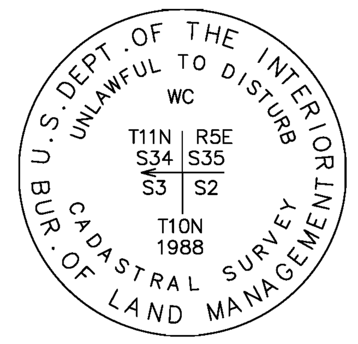
CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

| DRAWN BY CEZ | APPROVAL RECOMMENDED | | | |
|---|---|---|---|---|
| DATE 5/14/03 | Statewide Platting Supervisor | | | Date |
| SCALE 1" = 2 MILES | CHECKED APH | SHEET 2 of 21 | FILE NO. | LOCATED WITHIN EPF20020040A |



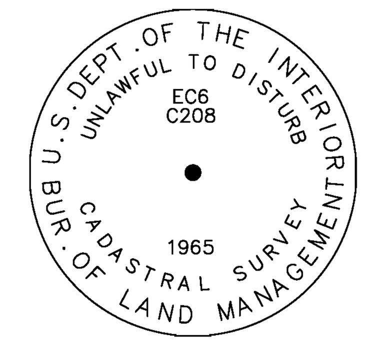

### MONUMENT No. 2

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°15-25.789" | LAT. 70°15'25.530" |
| LONG. 149°58'13.474" | LONG. 149°58'12.890" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,943,610.062 | N = 5,943,583.694 |
| E = 503,661.292 | E = 503,681.375 |



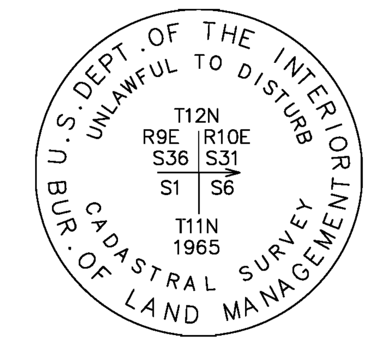

### MONUMENT No. 11

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°15'25.515" | LAT. 70°15'25.530" |
| LONG. 150°48'49.881" | LONG. 150°48'49.931" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,944,254.436 | N = 5,944,255.969 |
| E = 399,302.442 | E = 399,300.751 |



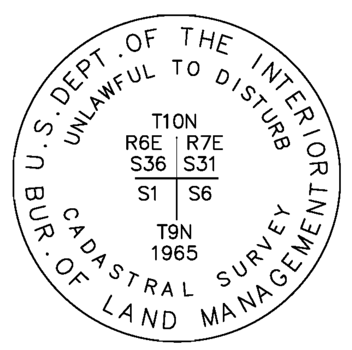

### MONUMENT No. 19

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°11'26.736" | LAT. 70°11'26.739" |
| LONG. 150°27'34.221" | LONG. 150°27'34.232" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,919,520.412 | N = 5,919,520.796 |
| E = 442,961.590 | E = 442,961.232 |



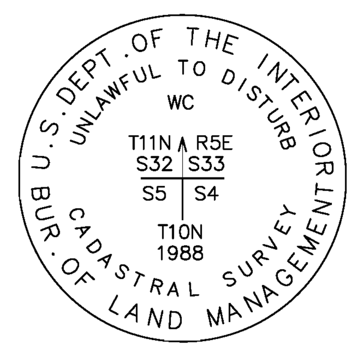

### MONUMENT No. 34

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°19'14.257" | LAT. 70°20'37.101" |
| LONG. 149°46'43.514" | LONG. 149°42'58.930" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,975,365.301 | N = 5,975,341.084 |
| E = 534,947.872 | E = 534,946.480 |



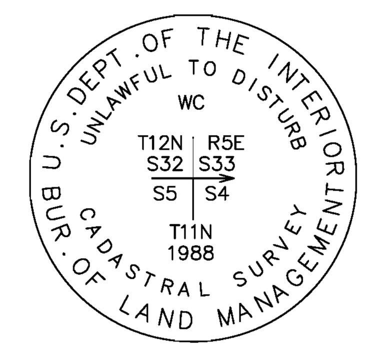

### MONUMENT No. 6

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°10'14.017" | LAT. 70°10'14.010" |
| LONG. 150°28'40.824" | LONG. 150°28'40.780" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,912,145.260 | N = 5,912,144.509 |
| E = 440,607.109 | E = 440,608.622 |



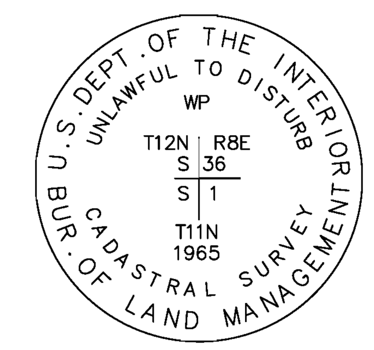

### MONUMENT No. 12

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°15'25.336" | LAT. 70°15'25.355" |
| LONG. 150°54'09.290" | LONG. 150°54'09.337" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,944,391.030 | N = 5,944,392.924 |
| E = 388,325.031 | E = 388,323.430 |



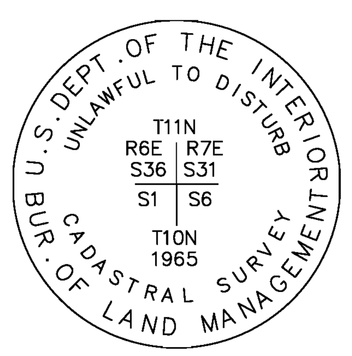

### MONUMENT No. 21

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°20'37.061" | LAT. 70°20'36.984" |
| LONG. 150°54'19.412" | LONG. 150°54'19.334" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,976,085.586 | N = 5,976,077.741 |
| E = 388,448.653 | E = 388,451.227 |



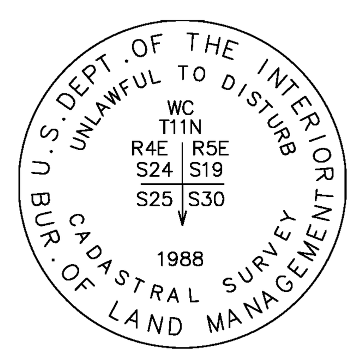

### MONUMENT No. 35

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°20'37.2545" | LAT. 70°20'37.101" |
| LONG. 149°58'39.909" | LONG. 149°58'39.653" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,975,275.775 | N = 5,975,260.131 |
| E = 502,741.149 | E = 502,749.901 |



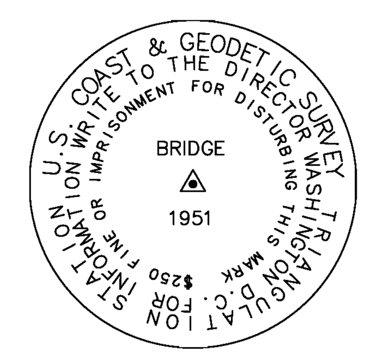

### MONUMENT No. 7

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°15'25.584" | LAT. 70°15'25.584" |
| LONG. 150°28'41.048" | LONG. 150°28'41.048" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,943,820.563 | N = 5,943,820.563 |
| E = 440,848.091 | E = 440,848.091 |



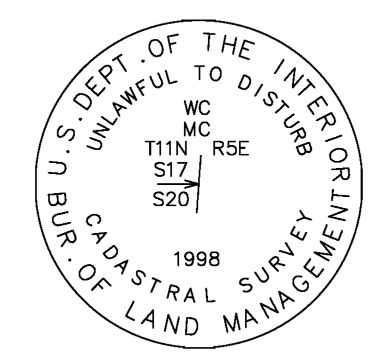

### MONUMENT No. 14

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°17'09.983" | LAT. 70°17'09.998" |
| LONG. 150°59'08.852" | LONG. 150°59'08.871" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,955,188.699 | N = 5,955,190.184 |
| E = 378,202.441 | E = 378,201.797 |



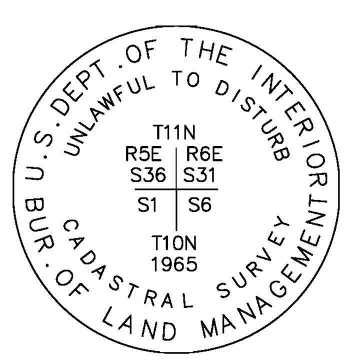

### MONUMENT No. 22

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°17'18.038" | LAT. 70°17'18.062" |
| LONG. 150°59'17.773" | LONG. 150°59'17.745" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,956,012.489 | N = 5,956,014.930 |
| E = 377,909.579 | E = 377,910.575 |



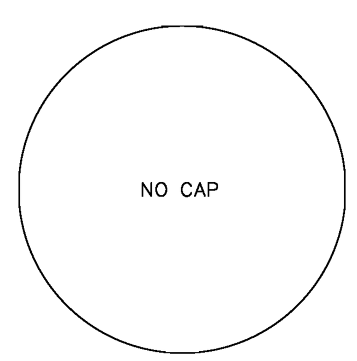

### MONUMENT No. 39

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°18'01.286" | LAT. 70°18'01.238" |
| LONG. 150°54'55.612" | LONG. 150°54'55.540" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,960,268.319 | N = 5,960,263.390 |
| E = 386,971.558 | E = 386,973.945 |



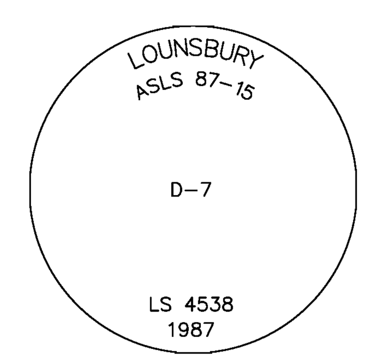

### MONUMENT No. 8

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°15'25.526" | LAT. 70°15'25.526" |
| LONG. 150°43'54.874" | LONG. 150°43'54.874" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,944,126.792 | N = 5,944,126.792 |
| E = 409,441.167 | E = 409,441.167 |



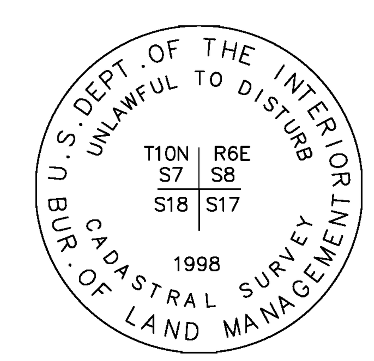

### MONUMENT No. 15

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°18'46.741" | LAT. 70°18'46.766" |
| LONG. 150°59'08.903" | LONG. 150°59'08.871" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,965,024.754 | N = 5,965,027.355 |
| E = 378,360.016 | E = 378,361.158 |



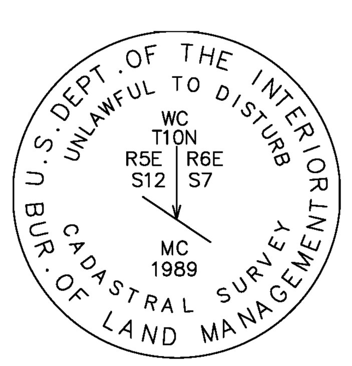

### MONUMENT No. 29

| BLM FOUND (NAD27) |
|---|
| LAT. 70°18'29.158" |
| LONG. 149°49'48.616" |
| ASP ZONE 4 |
| N = 5,962,281.067 |
| E = 520,961.187 |



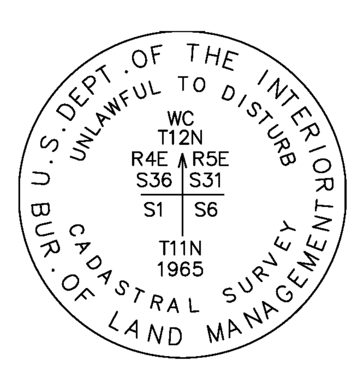

### MONUMENT No. 40

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°13'41.672" | LAT. 70°13'41.630" |
| LONG. 150°41'27.935" | LONG. 150°41'27.916" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,933,509.823 | N = 5,933,505.513 |
| E = 414,371.287 | E = 414,371.920 |



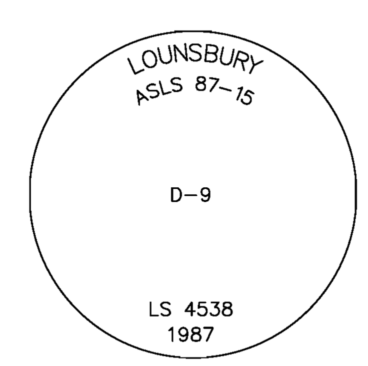

### MONUMENT No. 9

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°13'54.730" | LAT. 70°13'54.677" |
| LONG. 150°43'54.858" | LONG. 150°43'54.739" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,934,896.403 | N = 5,934,890.922 |
| E = 409,330.745 | E = 409,334.775 |



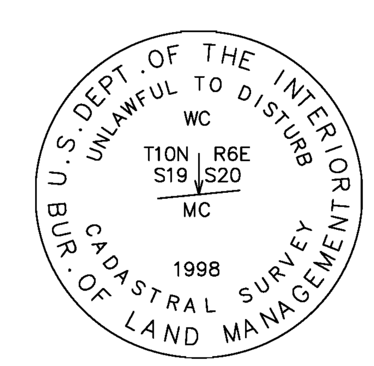

### MONUMENT No. 16

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°20'36.694" | LAT. 70°20'36.653" |
| LONG. 150°59'08.953" | LONG. 150°59'08.871" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,976,202.343 | N = 5,976,198.099 |
| E = 378,539.409 | E = 378,542.156 |



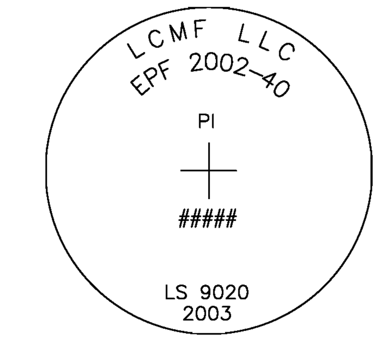

### MONUMENT No. 31

| BLM FOUND (NAD27) |
|---|
| LAT. 70°19'14.257" |
| LONG. 149°46'43.514" |
| ASP ZONE 4 |
| N = 5,966,886.653 |
| E = 527,290.685 |



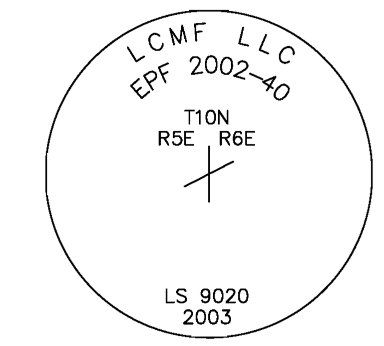

### MONUMENT No. 41

| BLM FOUND (NAD27) | BLM RECORD (NAD27) |
|---|---|
| LAT. 70°12'02.040" | LAT. 70°12'02.011" |
| LONG. 150°41'26.807" | LONG. 150°41'26.804" |
| ASP ZONE 4 | ASP ZONE 4 |
| N = 5,923,380.675 | N = 5,923,377.712 |
| E = 414,295.199 | E = 414,295.295 |



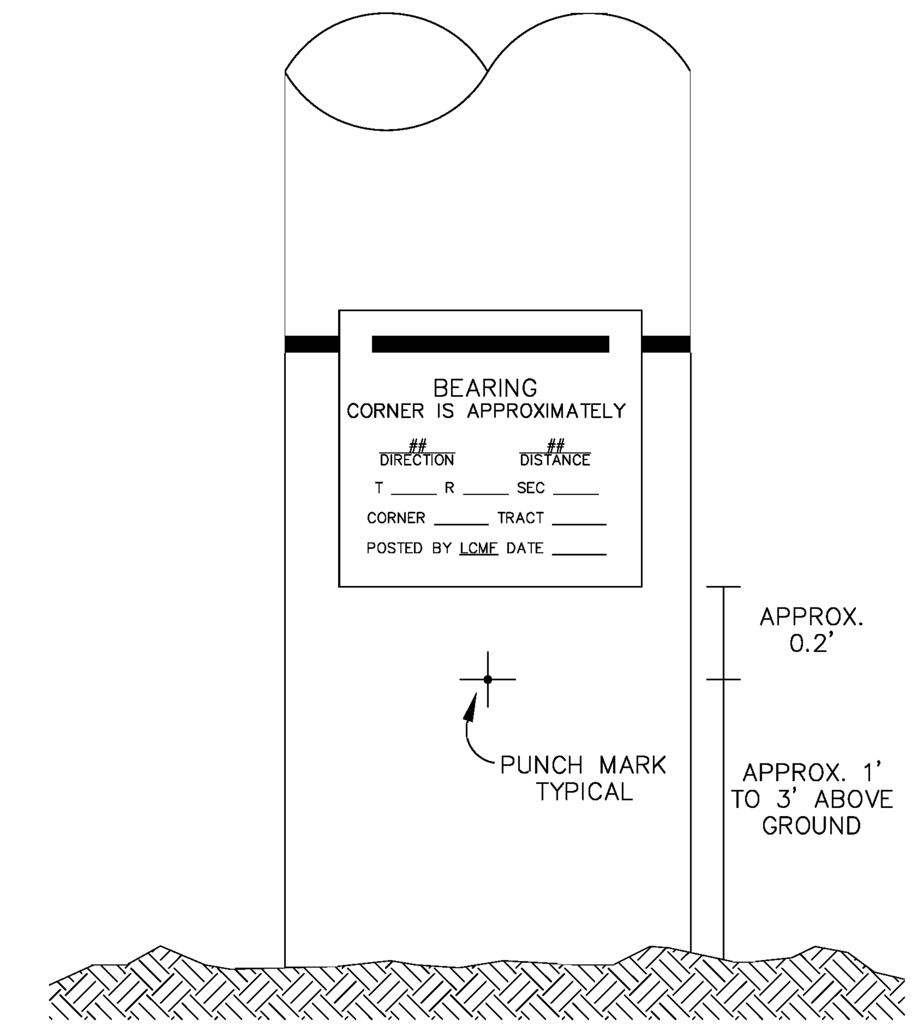

### TYPICAL PRIMARY MONUMENT SET THIS SURVEY

3 1/4" ALUMINUM MONUMENT ON 5/8"x30" REBAR DRIVEN 28" INTO GROUND




### TYPICAL PRIMARY CROSSING MONUMENT SET THIS SURVEY

3 1/4" ALUMINUM MONUMENT ON 5/8"x30" REBAR DRIVEN 28" INTO GROUND




N.T.S.

### TYPICAL SECONDARY MONUMENT SET THIS SURVEY

ALL RM's ARE PUNCH MARKS SET DEEPLY INTO THE FACE OF EXISTING VSM's, APPROX. 1' TO 3' ABOVE GROUND LEVEL, WITH CHISEL MARKS MAKING A +. VSM TYPICAL 12" DIAM., HEIGHT VARIES.

ALL BEARING TAGS ARE TYPICAL YELLOW ALUMINUM BEARING TREE TAGS STRAPPED TO VSM's WITH PLASTIC BINDING AND METAL CLIPS.

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01<br>Ending 4/12/01 | LCMF Incorporated<br>139 E. 51St.<br>Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

RECORD OF SURVEY
OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

| DRAWN BY CEZ | APPROVAL RECOMMENDED | | |
|---|---|---|---|
| DATE 5/14/03 | Statewide Platting Supervisor / Date | | |
| SCALE 1" = 2 MILES | CHECKED APH | SHEET 3 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |

04-11-20-1Rev4.DWG
Plot date: 04/06/2010 5:50 PM


| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING |
|---|---|---|---|---|
| POB | 70°20'37.366"N | 150°55'20.388"W | 5,976,147.922 | 386,362.412 |
| PI PY8 | 70°20'37.363"N | 150°55'20.813"W | 5,976,147.899 | 386,347.865 |
| PI PY6 | 70°20'36.577"N | 150°55'20.774"W | 5,976,067.983 | 386,347.975 |
| PI PY5.9 | 70°20'36.570"N | 150°55'19.996"W | 5,976,066.798 | 386,374.590 |
| PI PY5.1 | 70°20'36.209"N | 150°50'19.990"W | 5,976,030.152 | 386,374.250 |
| PI PY5 | 70°20'36.208"N | 150°55'20.740"W | 5,976,030.389 | 386,348.583 |
| PI PY1 | 70°20'35.100"N | 150°55'20.690"W | 5,975,917.710 | 386,348.588 |
| PI PW7A1 | 70°20'32.368"N | 150°55'28.585"W | 5,975,644.123 | 386,074.159 |
| PI PWYA2 | 70°20'32.644"N | 150°55'29.385"W | 5,975,672.592 | 386,047.217 |
| PI PW7A3 | 70°20'32.497"N | 150°55'29.813"W | 5,975,657.834 | 386,032.330 |
| PI PW7A4 | 70°20'32.226"N | 150°55'28.997"W | 5,975,629.926 | 386,059.856 |
| PI A2C3 | 70°20'37.421"N | 150°55'20.776"W | 5,976,153.787 | 386,349.207 |
| PI A2S2 | 70°20'37.386"N | 150°55'20.830"W | 5,976,150.206 | 386,347.309 |
| PI A2D2 | 70°20'37.305"N | 150°55'20.849"W | 5,976,142.012 | 386,346.523 |

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

DATE OF SURVEY
Beginning 3/01/01
Ending 4/12/01

NAME OF SURVEYOR
LCMF Incorporated
139 E. 51St.
Anch., Alaska 99503

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

# RECORD OF SURVEY

OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

DRAWN BY CEZ
DATE 5/14/03

APPROVAL RECOMMENDED
Statewide Platting Supervisor — Date

SCALE 1"=40' | CHECKED APH | SHEET 4 of 21 | FILE NO. LOCATED WITHIN EPF20020040A

04-11-20-1Rev4.DWG
Plot date: 04/06/2010 5:50 PM


| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING | RM #1 | DESC. | RM #2 | DESC. |
|---|---|---|---|---|---|---|---|---|
| 11B | 70°20'24.918"N | 150°55'50.049"W | 5,974,897.942 | 385,327.986 | 18.06' | VSM 10A | 16.02' | VSM 11B |
| 12B | 70°20'25.326"N | 150°55'51.303"W | 5,974,940.136 | 385,285.686 | 15.38' | VSM 12B | 17.50' | VSM 13A |
| 22B | 70°20'21.418"N | 150°56'02.565"W | 5,974,548.707 | 384,894.134 | 19.00' | VSM 21B | 18.31' | VSM 22A |
| 26B | 70°20'22.906"N | 150°56'07.077"W | 5,974,702.329 | 384,741.998 | 16.06' | VSM 26B | 23.81' | VSM 27A |
| 48B | 70°20'14.487"N | 150°56'35.817"W | 5,973,861.714 | 383,745.009 | 14.88' | VSM 47B | 17.04' | VSM 48A |
| 49B | 70°20'14.944"N | 150°56'36.940"W | 5,973,908.769 | 383,707.303 | 16.71' | VSM 49B | 18.75' | VSM 50A |
| PI 3 | 70°20'06.449"N | 150°57'05.961"W | 5,973,060.613 | 382,700.350 | 10.79' | VSM 0101A | 55.84' | VSM 0102 |
| 122A | 70°19'57.203"N | 150°57'32.390"W | 5,972,134.966 | 381,780.695 | 12.76' | VSM 0121 | 26.39' | VSM 0122 |
| 122B | 70°19'57.618"N | 150°57'33.624"W | 5,972,177.794 | 381,739.095 | 32.03' | VSM 0122 | 17.34' | VSM 0123 |

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

DATE OF SURVEY
Beginning 3/01/01
Ending 4/12/01

NAME OF SURVEYOR
LCMF Incorporated
139 E. 51St.
Anch., Alaska 99503

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

# RECORD OF SURVEY

OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

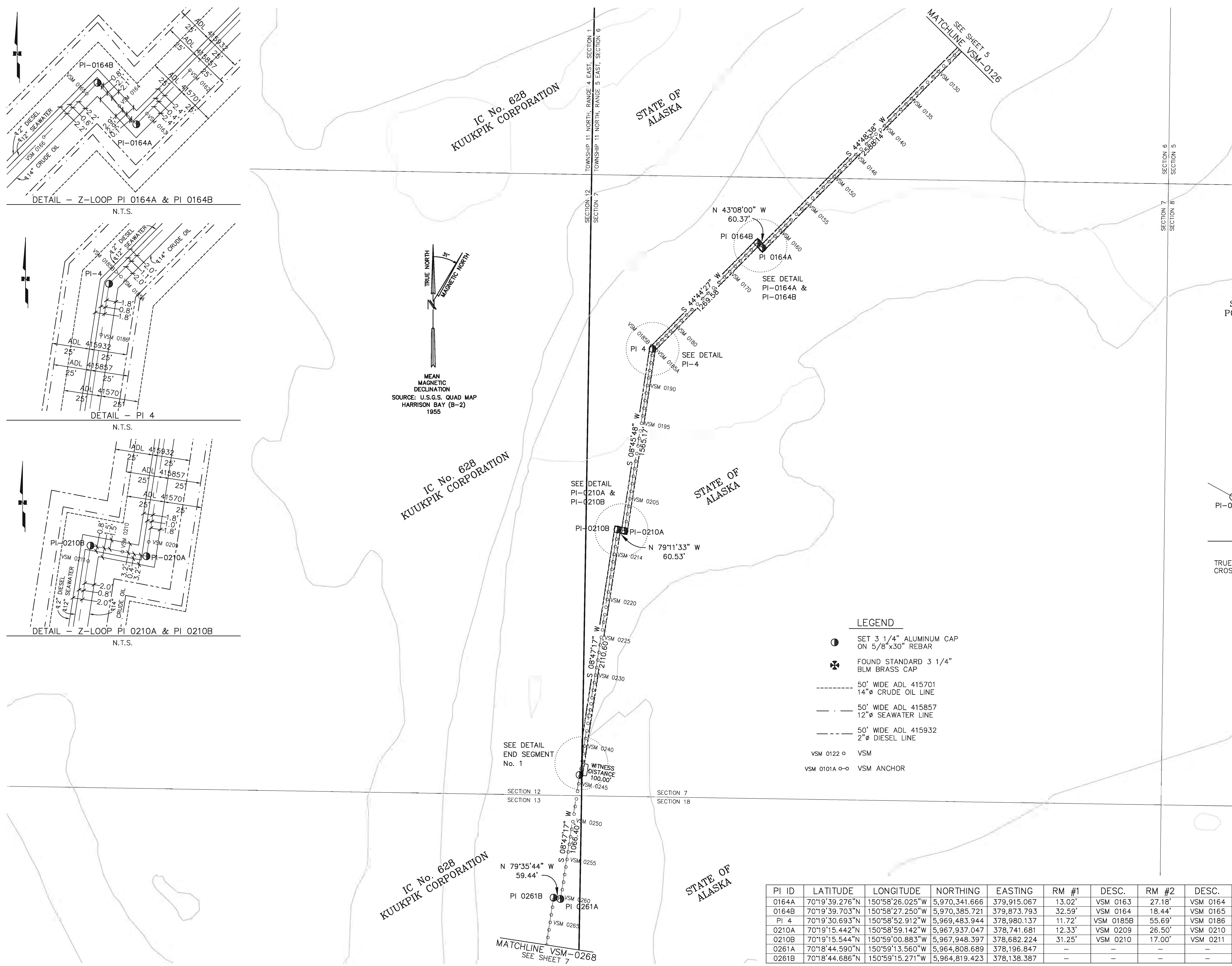
LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

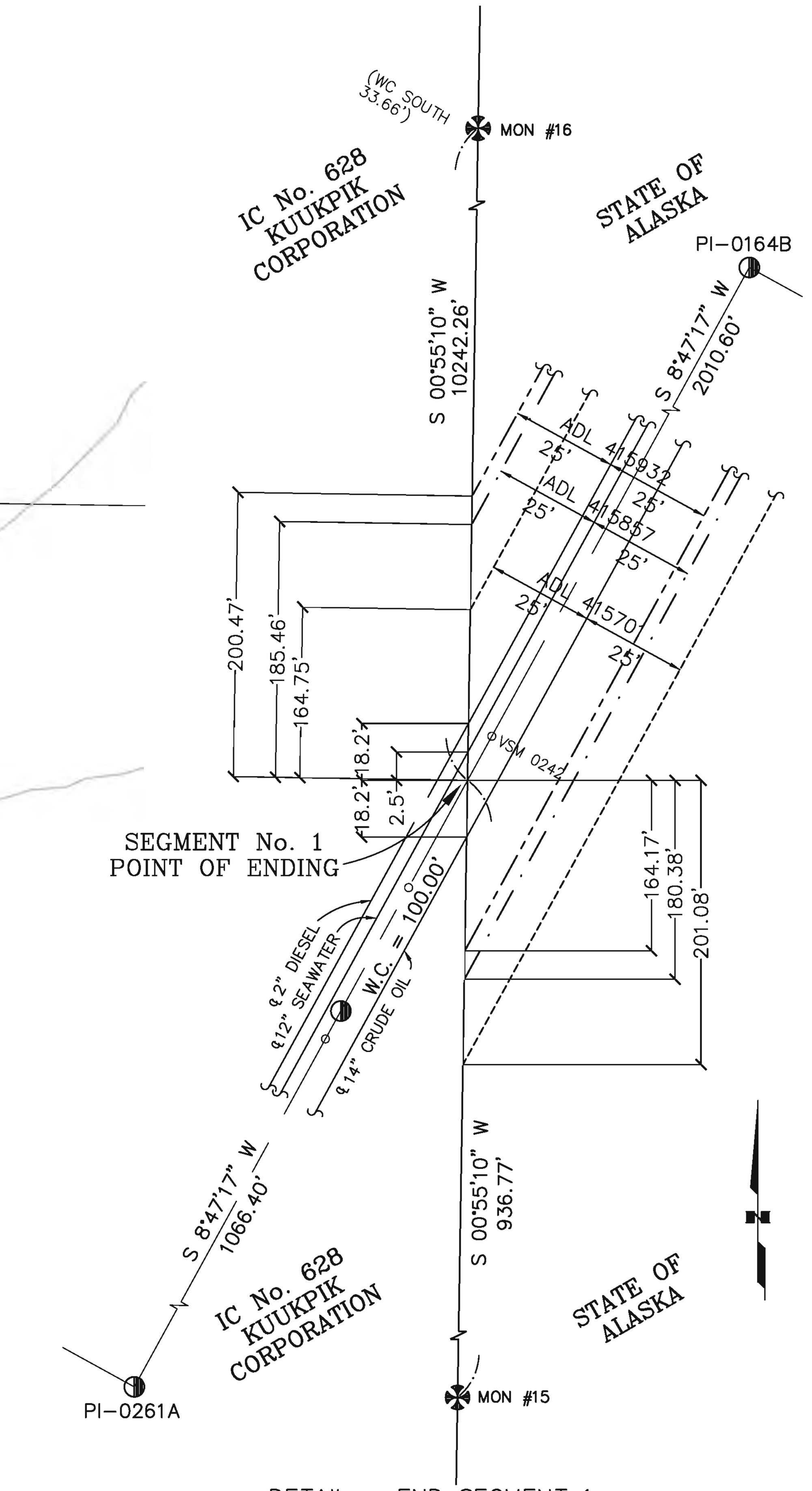
CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

DRAWN BY CEZ
DATE 5/14/03

APPROVAL RECOMMENDED
Statewide Platting Supervisor
Date

SCALE 1"=200'
CHECKED APH
SHEET 5 of 21
FILE NO. LOCATED WITHIN EPF20020040A




DETAIL – END SEGMENT 1
N.T.S.

TRUE POSITION OF TOWNSHIP 11 NORTH, RANGES 4 AND 5 EAST, CROSSING (POINT OF ENDING OF SEGMENT No. 1) FALLS IN POND.

| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING | RM #1 | DESC. | RM #2 | DESC. |
|---|---|---|---|---|---|---|---|---|
| 0164A | 70°19'39.276"N | 150°58'26.025"W | 5,970,341.666 | 379,915.067 | 13.02' | VSM 0163 | 27.18' | VSM 0164 |
| 0164B | 70°19'39.703"N | 150°58'27.250"W | 5,970,385.721 | 379,873.793 | 32.59' | VSM 0164 | 18.44' | VSM 0165 |
| PI 4 | 70°19'30.693"N | 150°58'52.912"W | 5,969,483.944 | 378,980.137 | 11.72' | VSM 0185B | 55.69' | VSM 0186 |
| 0210A | 70°19'15.442"N | 150°58'59.142"W | 5,967,937.047 | 378,741.681 | 12.33' | VSM 0209 | 26.50' | VSM 0210 |
| 0210B | 70°19'15.544"N | 150°59'00.883"W | 5,967,948.397 | 378,682.224 | 31.25' | VSM 0210 | 17.00' | VSM 0211 |
| 0261A | 70°18'44.590"N | 150°59'13.560"W | 5,964,808.689 | 378,196.847 | – | – | – | – |
| 0261B | 70°18'44.686"N | 150°59'15.271"W | 5,964,819.423 | 378,138.387 | – | – | – | – |

0 200 400 800 1200 FEET
0 60 120 240 360 METERS

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

DATE OF SURVEY
Beginning 3/01/01
Ending 4/12/01

NAME OF SURVEYOR
LCMF Incorporated
139 E. 51St.
Anch., Alaska 99503

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

# RECORD OF SURVEY
OF THE ALPINE TO KUPARUK CPF–2 OVERLAND PIPELINE

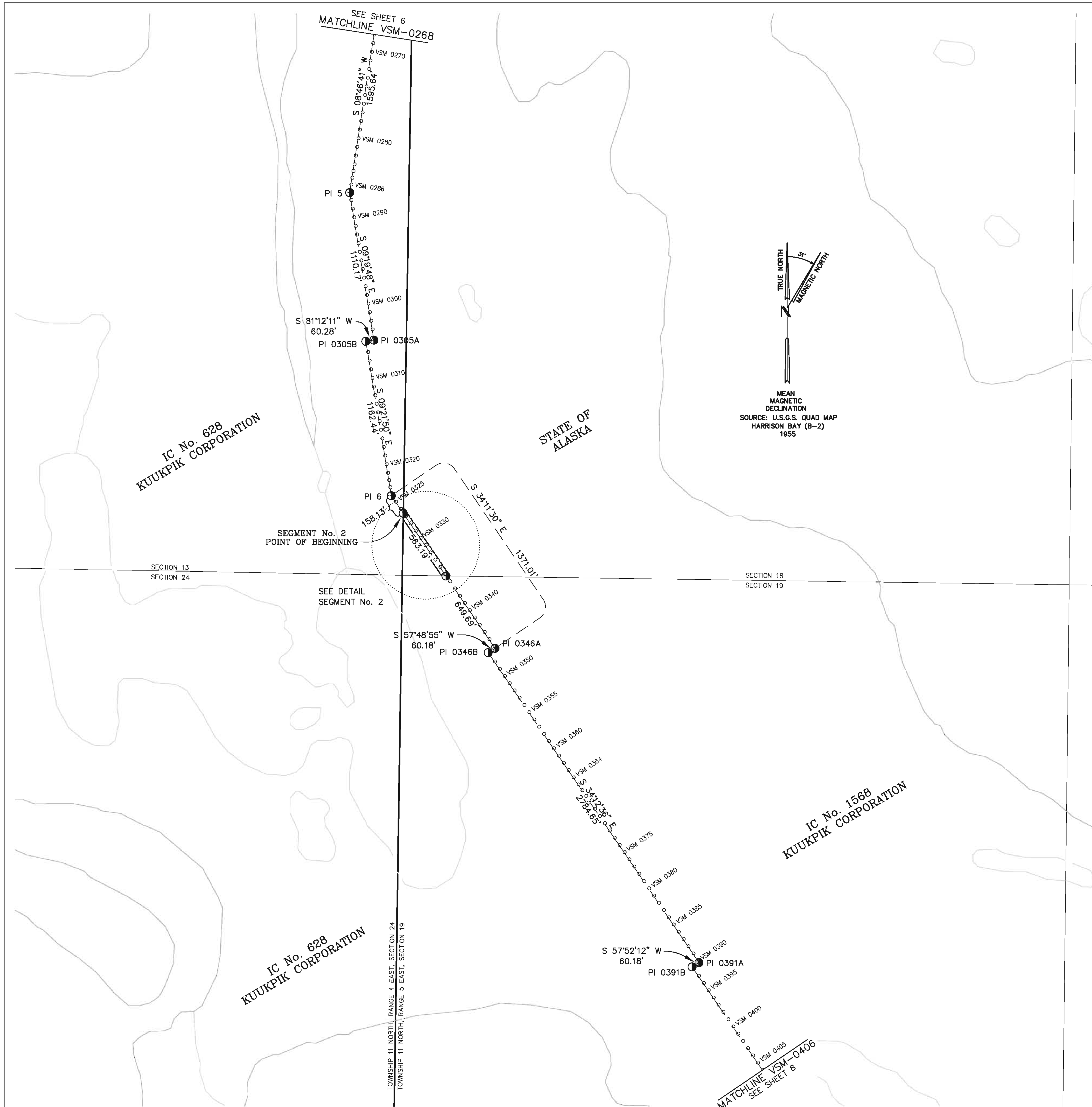
LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

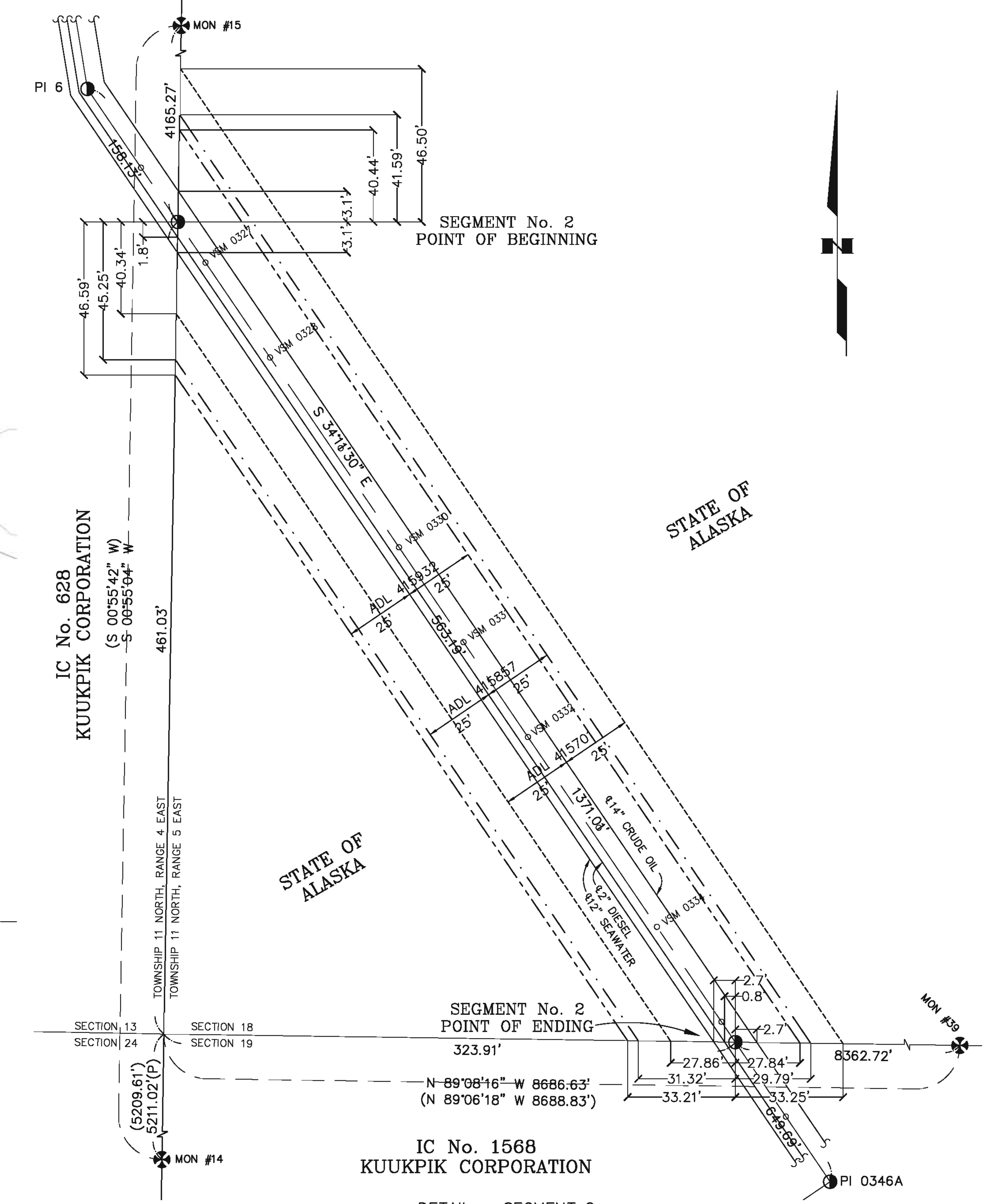
CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

DRAWN BY CEZ
DATE 5/14/03

APPROVAL RECOMMENDED
Statewide Platting Supervisor    Date

SCALE 1"=400'
CHECKED APH
SHEET 6 of 21
FILE NO. LOCATED WITHIN EPF20020040A




DETAIL – SEGMENT 2
N.T.S.

## LEGEND

| | |
|---|---|
| ◑ | SET 3 1/4" ALUMINUM CAP ON 5/8"x30" REBAR |
| ✠ | FOUND STANDARD 3 1/4" BLM BRASS CAP |
| 5211.02'(P) | PRORATED DIMENSION |
| - - - - - - | 50' WIDE ADL 415701 14"ø CRUDE OIL LINE |
| — · — | 50' WIDE ADL 415857 12"ø SEAWATER LINE |
| — — — | 50' WIDE ADL 415932 2"ø DIESEL LINE |
| VSM 0122 o | VSM |
| VSM 0101A o-o | VSM ANCHOR |

0 200 400 800 1200 FEET
0 60 120 240 360 METERS

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING |
|---|---|---|---|---|
| PI 5 | 70°18'29.139"N | 150°59'21.626"W | 5,963,242.477 | 377,894.883 |
| 0305A | 70°18'18.394"N | 150°59'15.858"W | 5,962,146.996 | 378,074.863 |
| 0305B | 70°18'18.294"N | 150°59'17.591"W | 5,962,137.777 | 378,015.290 |
| PI 6 | 70°18'07.044"N | 150°59'11.534"W | 5,960,990.824 | 378,204.427 |
| 0346A | 70°17'56.014"N | 150°58'48.539"W | 5,959,856.773 | 378,974.885 |
| 0346B | 70°17'55.690"N | 150°58'50.009"W | 5,959,824.717 | 378,923.951 |
| 0391A | 70°17'33.289"N | 150°58'03.304"W | 5,957,521.861 | 380,489.556 |
| 0391B | 70°17'32.967"N | 150°58'04.774"W | 5,957,489.853 | 380,438.590 |

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01 | LCMF Incorporated |
| Ending 4/12/01 | 139 E. 51St. Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

RECORD OF SURVEY
OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE
LOCATED WITHIN
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CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

| DRAWN BY CEZ | APPROVAL RECOMMENDED | | |
|---|---|---|---|
| DATE 5/14/03 | Statewide Plotting Supervisor | | Date |
| SCALE 1"=400' | CHECKED APH | SHEET 7 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |


1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING |
|---|---|---|---|---|
| 0435A | 70°17'10.798"N | 150°57'18.559"W | 5,955,211.161 | 381,988.742 |
| 0435B | 70°17'10.472"N | 150°57'20.027"W | 5,955,178.834 | 381,937.823 |
| PI 7 | 70°17'00.626"N | 150°56'59.495"W | 5,954,166.917 | 382,626.814 |
| 0467A | 70°16'53.563"N | 150°56'58.637"W | 5,953,448.397 | 382,645.067 |
| 0467B | 70°16'53.545"N | 150°57'00.385"W | 5,953,447.572 | 382,585.031 |
| PI 8 | 70°16'45.913"N | 150°56'59.406"W | 5,952,671.187 | 382,606.544 |
| 0494A | 70°16'38.893"N | 150°56'45.967"W | 5,951,950.301 | 383,056.785 |
| 0494B | 70°16'38.580"N | 150°56'47.461"W | 5,951,919.287 | 383,005.021 |
| PI 9 | 70°16'31.182"N | 150°56'33.286"W | 5,951,159.717 | 383,480.036 |
| 0525A | 70°16'24.504"N | 150°56'12.685"W | 5,950,469.898 | 384,176.939 |
| 0525B | 70°16'24.088"N | 150°56'13.928"W | 5,950,428.261 | 384,133.595 |
| PI 10 | 70°16'17.306"N | 150°55'52.973"W | 5,949,727.814 | 384,842.608 |
| 0563A | 70°16'11.859"N | 150°55'16.471"W | 5,949,155.013 | 386,087.808 |
| 0563B | 70°16'11.329"N | 150°55'17.244"W | 5,949,101.553 | 386,060.455 |

DATE OF SURVEY
Beginning 3/01/01
Ending 4/12/01

NAME OF SURVEYOR
LCMF Incorporated
139 E. 51St.
Anch., Alaska 99503

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

# RECORD OF SURVEY
## OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

LOCATED WITHIN
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SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

DRAWN BY CEZ
DATE 5/14/03

APPROVAL RECOMMENDED
Statewide Platting Supervisor — Date

| SCALE | CHECKED | SHEET | FILE NO. |
|---|---|---|---|
| 1"=400' | APH | 8 of 21 | LOCATED WITHIN EPF20020040A |


| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING |
|---|---|---|---|---|
| 0607A | 70°16'00.573"N | 150°54'05.226"W | 5,947,971.093 | 388,517.745 |
| 0607B | 70°16'00.046"N | 150°54'06.009"W | 5,947,917.896 | 388,490.057 |
| 0651A | 70°15'49.225"N | 150°52'53.606"W | 5,946,781.386 | 390,961.234 |
| 0651B | 70°15'48.696"N | 150°52'54.382"W | 5,946,727.972 | 390,933.793 |
| PI 11 | 70°15'43.541"N | 150°52'19.893"W | 5,946,186.847 | 392,111.190 |
| 0685A | 70°15'37.795"N | 150°52'04.657"W | 5,945,595.257 | 392,626.349 |
| 0685B | 70°15'37.401"N | 150°52'05.965"W | 5,945,555.844 | 392,580.835 |
| PI 12A | 70°15'31.193"N | 150°51'49.452"W | 5,944,916.679 | 393,139.275 |
| 0719A | 70°15'19.185"N | 150°51'43.457"W | 5,943,693.059 | 393,328.014 |
| 0719B | 70°15'19.097"N | 150°51'45.180"W | 5,943,684.968 | 393,268.663 |

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01<br>Ending 4/12/01 | LCMF Incorporated<br>139 E. 51St.<br>Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

# DIVISION OF MINING, LAND AND WATER

ANCHORAGE, ALASKA

# RECORD OF SURVEY

## OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

LOCATED WITHIN
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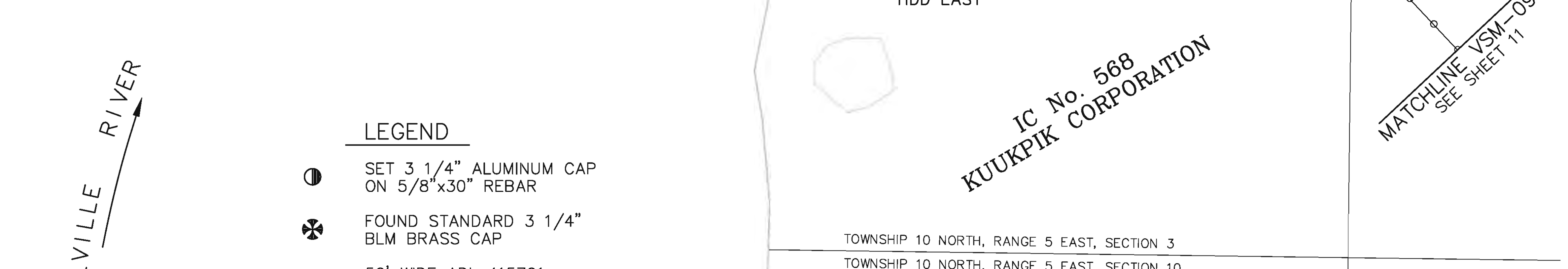
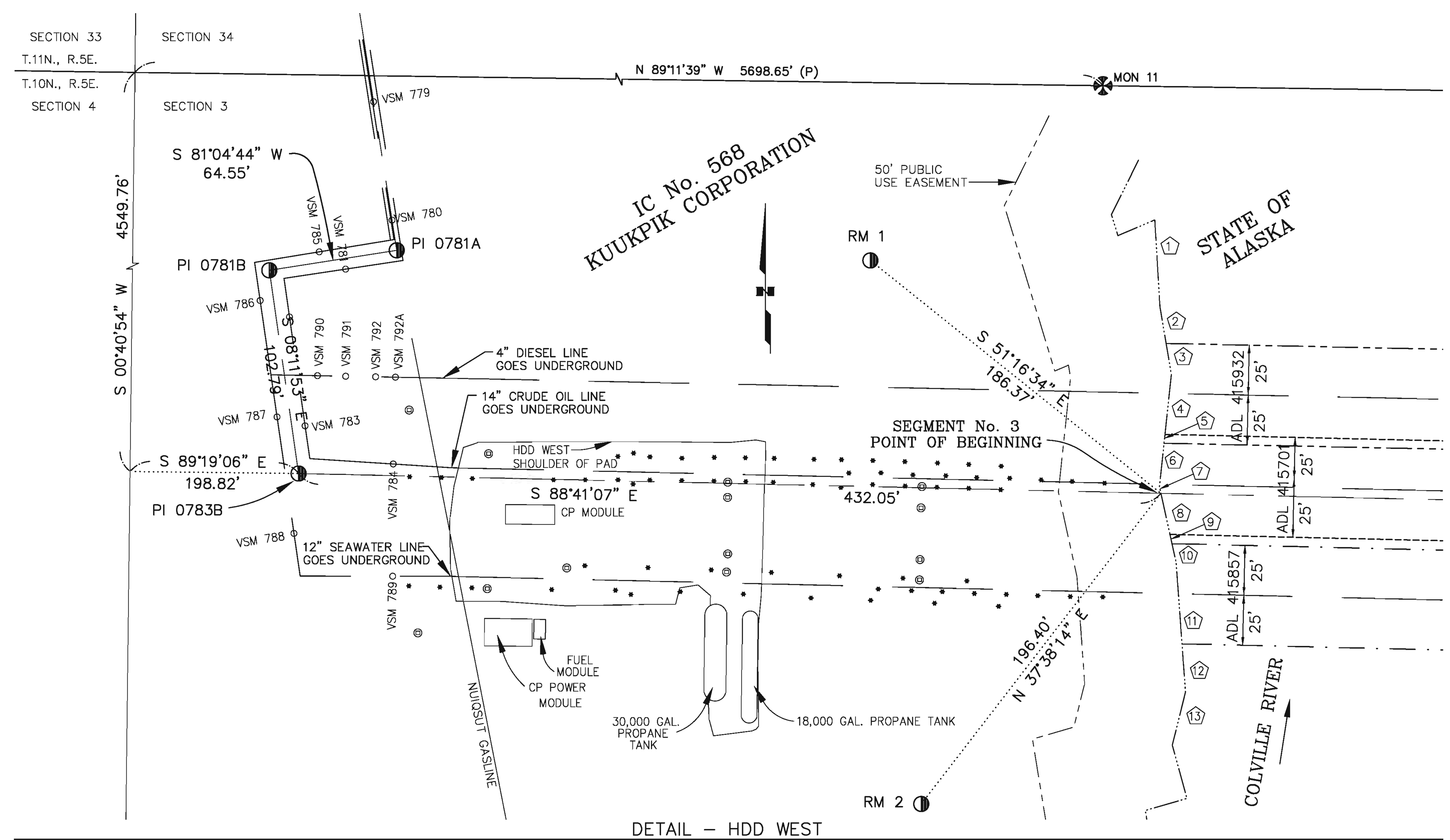
CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

| DRAWN BY CEZ<br>DATE 5/14/03 | APPROVAL RECOMMENDED<br>Statewide Platting Supervisor — Date | | |
|---|---|---|---|
| SCALE 1"=400' | CHECKED APH | SHEET 9 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |


## HDD EAST MEANDER CHART

| | | |
|---|---|---|
| 1 | S 30°19'59" E | 36.59' |
| 2 | S 11°27'12" W | 14.19' |
| 3 | S 66°34'32" E | 5.88' |
| 4 | S 66°34'32" E | 6.80' |
| 5 | S 23°18'36" E | 10.01' |
| 6 | S 71°11'23" W | 21.39' |
| 7 | S 2°50'05" E | 20.19' |
| 8 | N 84°04'41" E | 15.79' |
| 9 | S 30°05'52" E | 15.00' |
| 10 | S 30°05'52" E | 3.71' |
| 11 | S 30°05'52" E | 9.57' |
| 12 | S 57°12'52" W | 17.60' |
| 13 | S 0°36'02" E | 10.37' |
| 14 | S 0°36'02" E | 16.82' |
| 15 | S 38°10'42" E | 6.21' |
| 16 | S 38°10'42" E | 9.08' |
| 17 | S 38°10'42" E | 14.01' |
| 18 | S 32°17'35" W | 29.28' |
| 19 | S 18°15'08" E | 14.95' |
| 20 | S 18°15'08" E | 8.28' |
| 21 | S 68°45'02" E | 12.42' |
| 22 | S 16°21'06" W | 20.31' |
| 23 | S 33°15'06" E | 19.72' |




DETAIL - HDD WEST
N.T.S.

## HDD WEST MEANDER CHART

| | | |
|---|---|---|
| 1 | S 3°21'08" E | 43.62' |
| 2 | S 9°34'27" E | 18.54' |
| 3 | S 9°34'27" E | 15.82' |
| 4 | S 6°04'27" W | 30.12' |
| 5 | S 6°04'27" W | 4.47' |
| 6 | S 6°04'27" W | 21.78' |
| 7 | S 12°23'29" E | 3.48' |
| 8 | S 12°23'29" E | 21.06' |
| 9 | S 12°23'29" E | 4.72' |
| 10 | S 12°23'29" E | 9.59' |
| 11 | S 4°08'46" E | 40.87' |
| 12 | S 4°08'46" E | 24.22' |
| 13 | S 13°55'35" W | 27.42' |

## LEGEND

- SET 3 1/4" ALUMINUM CAP ON 5/8"x30" REBAR
- FOUND STANDARD 3 1/4" BLM BRASS CAP
- 50' WIDE ADL 415701 14"ø CRUDE OIL LINE
- 50' WIDE ADL 415857 12"ø SEAWATER LINE
- 50' WIDE ADL 415932 2"ø DIESEL LINE
- VSM 0122 o VSM
- VSM ANCHOR
- HEAT PIPE 3" SCH 40 STEEL PIPE (TYP)
- THERMISTOR STRING (TYP)

| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING |
|---|---|---|---|---|
| 0760A | 70°14'54.229"N | 150°51'32.677"W | 5,941,150.784 | 393,662.733 |
| 0760B | 70°14'54.143"N | 150°51'34.401"W | 5,941,142.927 | 393,603.309 |
| 0781A | 70°14'41.892"N | 150°51'28.224"W | 5,939,894.536 | 393,798.148 |
| 0781B | 70°14'41.785"N | 150°51'30.074"W | 5,939,884.526 | 393,734.380 |
| 0783B | 70°14'40.787"N | 150°51'29.606"W | 5,939,782.783 | 393,749.038 |
| 0891A | 70°14'40.384"N | 150°49'19.633"W | 5,939,680.211 | 398,217.995 |
| 0891B | 70°14'41.442"N | 150°49'19.656"W | 5,939,787.767 | 398,218.661 |
| 0895A | 70°14'41.426"N | 150°49'16.914"W | 5,939,784.855 | 398,312.929 |
| 0895B | 70°14'41.066"N | 150°49'16.968"W | 5,939,748.237 | 398,310.578 |
| PI 14A | 70°14'41.033"N | 150°49'06.328"W | 5,939,740.031 | 398,676.409 |

0 100 200 400 600 FEET
0 50 100 200 METERS

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01<br>Ending 4/12/01 | LCMF Incorporated<br>139 E. 51St.<br>Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

# RECORD OF SURVEY

OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

LOCATED WITHIN
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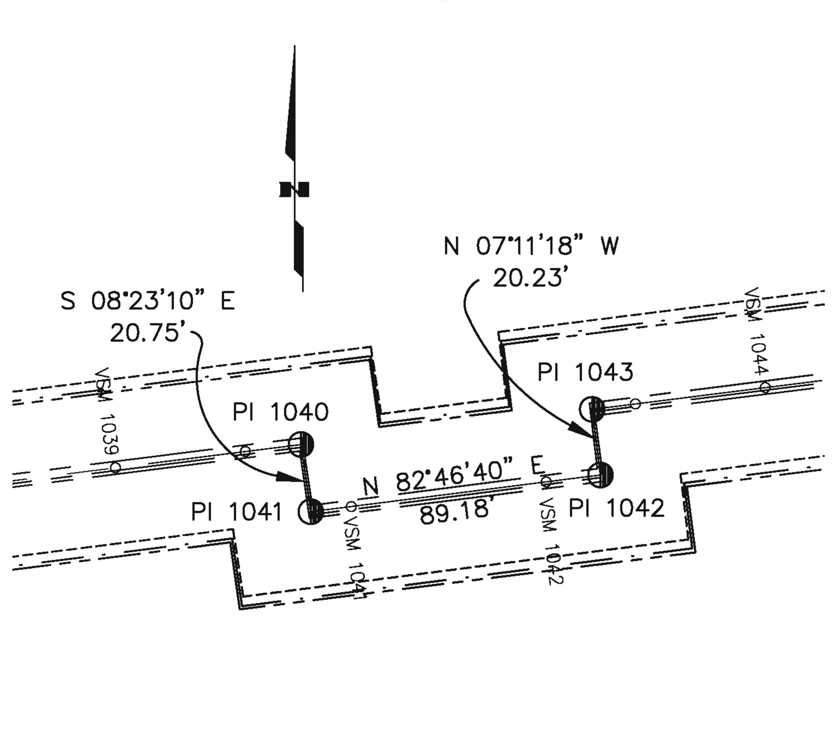
CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

| DRAWN BY CEZ<br>DATE 5/14/03 | APPROVAL RECOMMENDED<br>Statewide Platting Supervisor — Date | | |
|---|---|---|---|
| SCALE 1"=200' | CHECKED APH | SHEET 10 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |


DETAIL – VERTICAL LOOP #3

N.T.S.

| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING |
|---|---|---|---|---|
| 0923A | 70°14'31.333"N | 150°48'38.726"W | 5,938,741.148 | 399,612.459 |
| 0923B | 70°14'30.930"N | 150°48'40.005"W | 5,938,700.772 | 399,567.934 |
| 0968A | 70°14'11.120"N | 150°47'43.611"W | 5,936,661.339 | 401,481.142 |
| 0968B | 70°14'10.727"N | 150°47'44.920"W | 5,936,621.925 | 401,435.591 |
| PI 15A | 70°14'00.730"N | 150°47'16.478"W | 5,935,592.950 | 402,400.908 |
| 1018A | 70°14'03.023"N | 150°46'27.638"W | 5,935,804.515 | 404,084.324 |
| 1018B | 70°14'02.435"N | 150°46'27.442"W | 5,935,744.650 | 404,090.292 |
| 1040 | 70°14'04.290"N | 150°45'47.913"W | 5,935,916.023 | 405,452.704 |
| 1041 | 70°14'04.088"N | 150°45'47.818"W | 5,935,895.490 | 405,455.731 |
| 1042 | 70°14'04.210"N | 150°45'45.251"W | 5,935,906.701 | 405,544.200 |
| 1043 | 70°14'04.407"N | 150°45'45.332"W | 5,935,926.769 | 405,541.669 |
| 1074A | 70°14'07.037"N | 150°44'49.081"W | 5,936,170.176 | 407,480.258 |
| 1074B | 70°14'06.443"N | 150°44'48.917"W | 5,936,109.714 | 407,485.179 |
| PI 17A | 70°14'08.660"N | 150°44'01.730"W | 5,936,315.331 | 409,111.345 |
| 1125A | 70°13'55.368"N | 150°43'38.818"W | 5,934,954.577 | 409,883.449 |
| 1125B | 70°13'55.083"N | 150°43'40.357"W | 5,934,926.240 | 409,830.133 |

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| DATE OF SURVEY | NAME OF SURVEYOR |
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STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

## DIVISION OF MINING, LAND AND WATER

ANCHORAGE, ALASKA

# RECORD OF SURVEY

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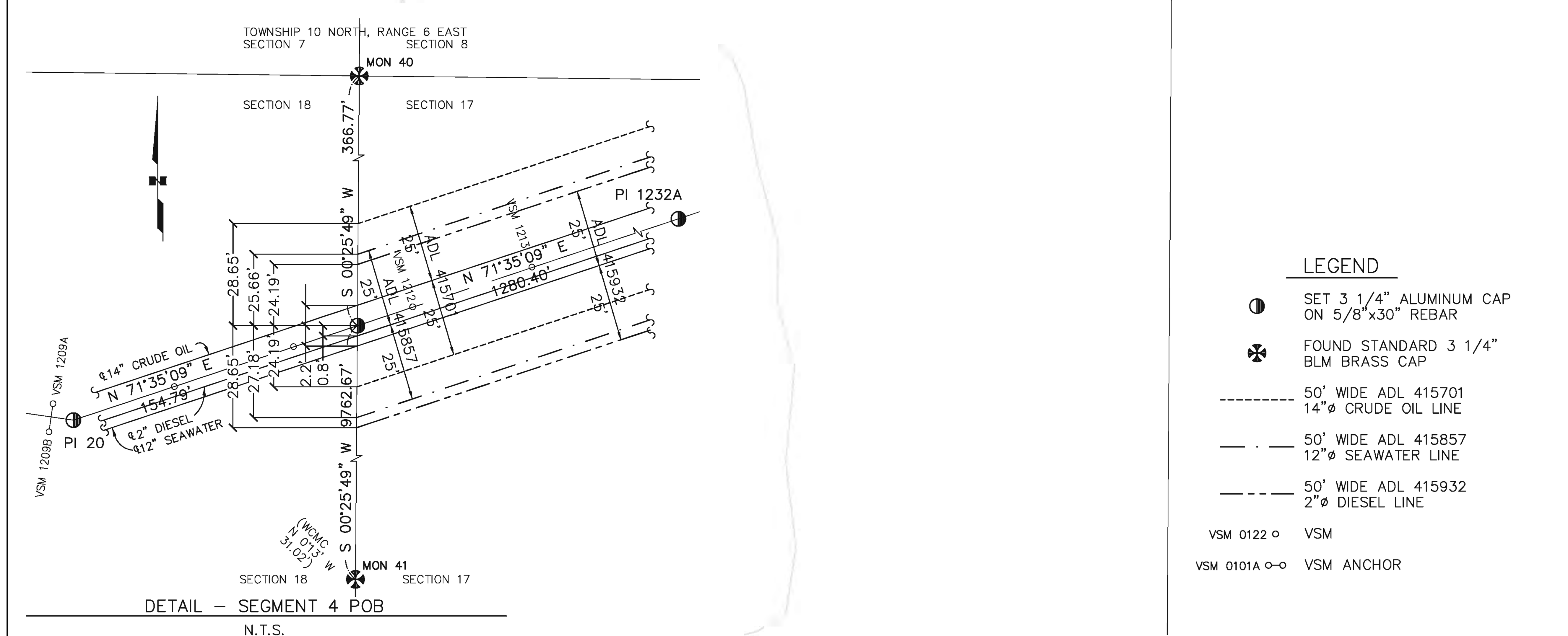
CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

| DRAWN BY | APPROVAL RECOMMENDED | | | |
|---|---|---|---|---|
| CEZ<br>DATE 5/14/03 | Statewide Platting Supervisor | | Date | |
| SCALE 1"=400' | CHECKED APH | SHEET 11 of 21 | FILE NO. | LOCATED WITHIN EPF20020040A |


| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING | RM #1 | DESC. | RM #2 | DESC. |
|---|---|---|---|---|---|---|---|---|
| PI 19 | 70°13'43.608"N | 150°43'20.510"W | 5,933,751.563 | 410,499.225 | – | – | – | – |
| 1162A | 70°13'42.422"N | 150°42'54.147"W | 5,933,620.295 | 411,405.091 | – | – | – | – |
| 1162B | 70°13'41.835"N | 150°42'54.396"W | 5,933,560.732 | 411,395.821 | – | – | – | – |
| 1193A | 70°13'39.394"N | 150°41'59.723"W | 5,933,290.741 | 413,274.602 | – | – | – | – |
| 1193B | 70°13'38.809"N | 150°42'00.003"W | 5,933,231.357 | 413,264.305 | – | – | – | – |
| PI 20 | 70°13'37.567"N | 150°41'32.145"W | 5,933,094.170 | 414,221.666 | – | – | – | – |
| 1232A | 70°13'42.177"N | 150°40'52.734"W | 5,933,547.525 | 415,583.371 | 12.95' | VSM 1231 | 26.80' | VSM 1232 |
| 1232B | 70°13'41.618"N | 150°40'52.204"W | 5,933,490.478 | 415,600.974 | 32.25' | VSM 1232 | 18.03' | VSM 1233 |
| 1285A | 70°13'52.322"N | 150°39'20.802"W | 5,934,544.109 | 418,758.416 | 13.32' | VSM 1284 | 26.78' | VSM 1285 |
| 1285B | 70°13'51.759"N | 150°39'20.279"W | 5,934,486.673 | 418,775.813 | 32.58 | VSM 1285 | 18.14' | VSM 1286 |
| PI 21 | 70°13'57.630"N | 150°38'30.194"W | 5,935,065.123 | 420,505.615 | 9.17' | VSM 1315B | 56.18' | VSM 1316 |

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01<br>Ending 4/12/01 | LCMF Incorporated<br>139 E. 51St.<br>Anch., Alaska 99503 |

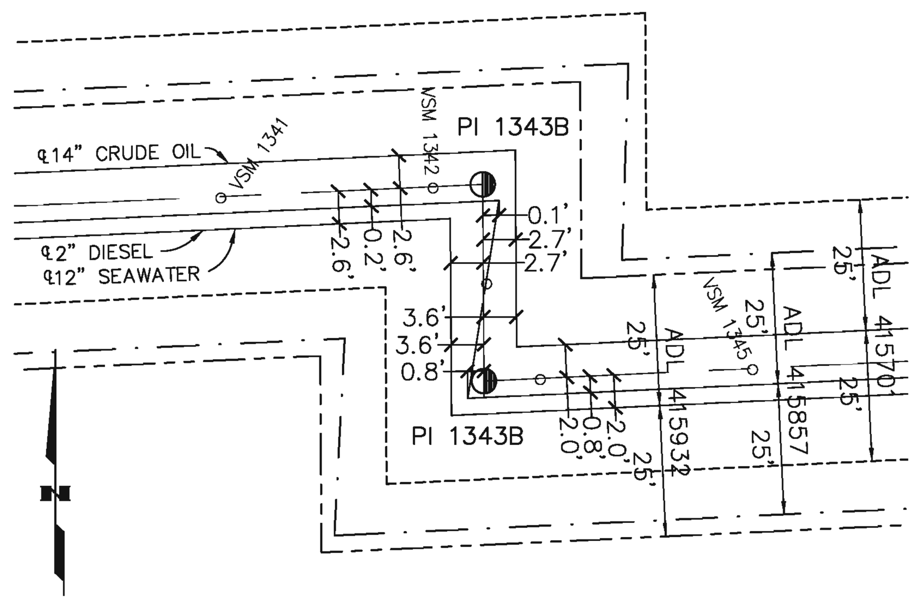
STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
## DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

# RECORD OF SURVEY
## OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

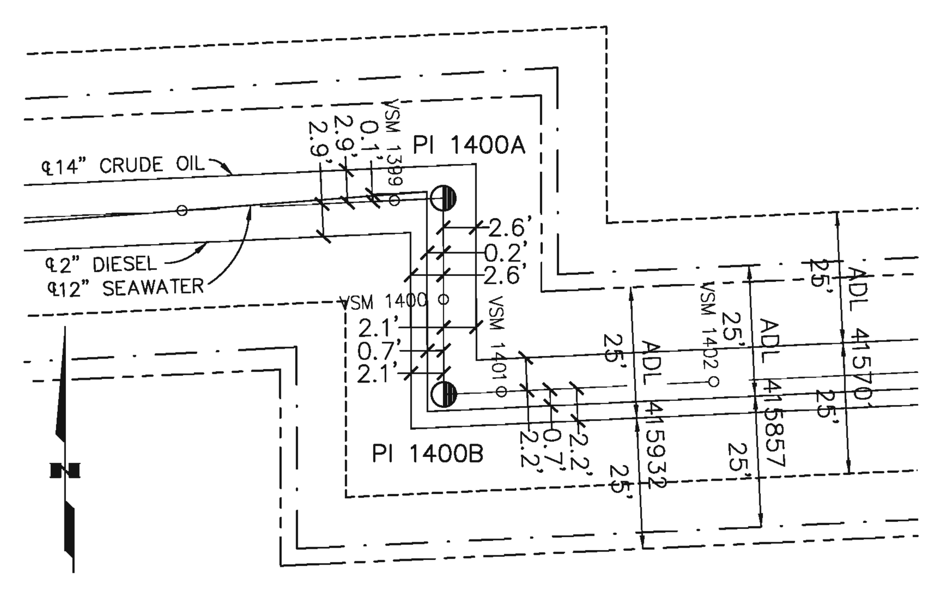
LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

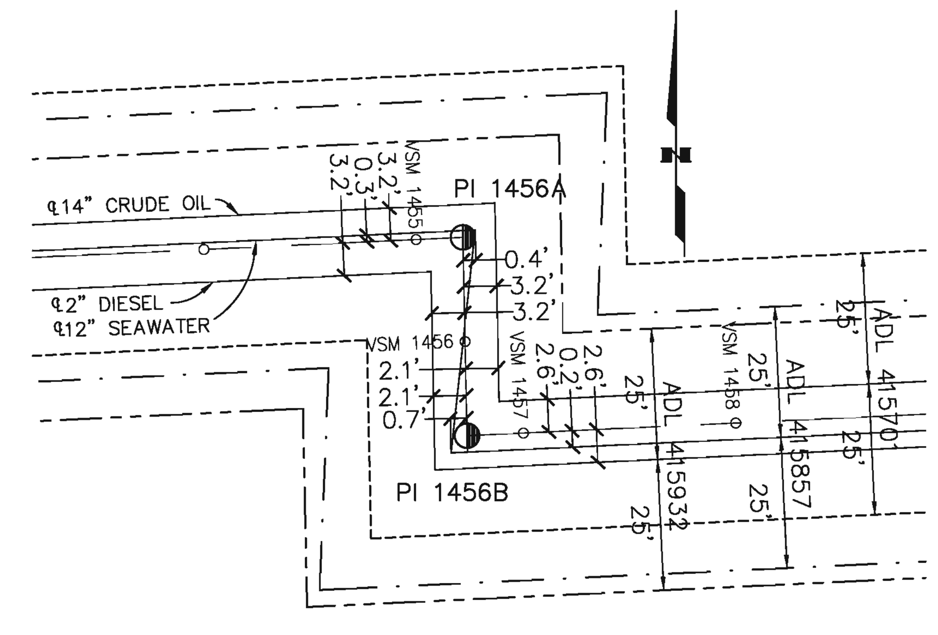
| DRAWN BY CEZ<br>DATE 5/14/03 | APPROVAL RECOMMENDED<br><br>Statewide Platting Supervisor — Date | | |
|---|---|---|---|
| SCALE 1"=400' | CHECKED APH | SHEET 12 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |



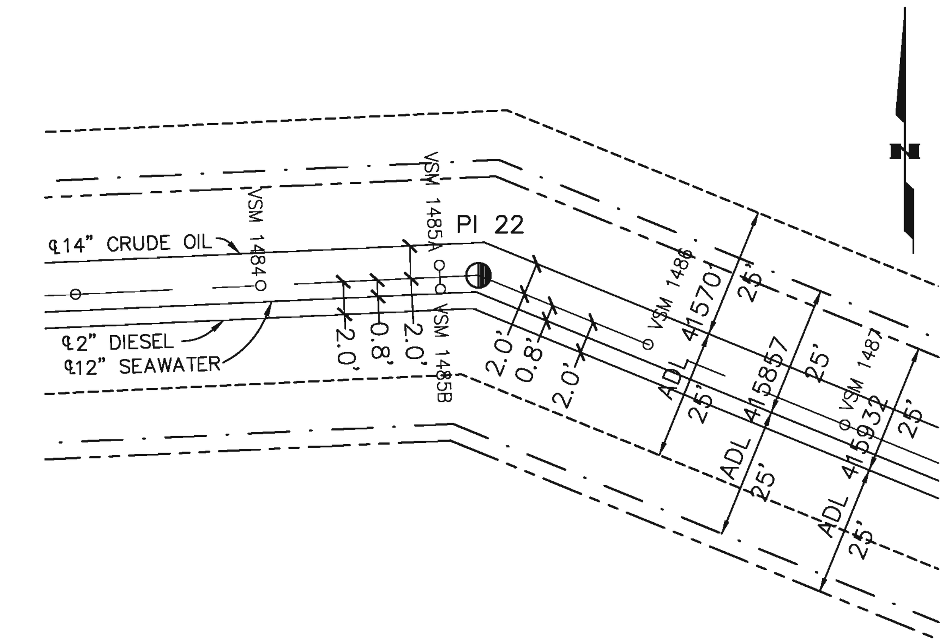

DETAIL – Z-LOOP PI 1343A & PI 1343B
N.T.S.



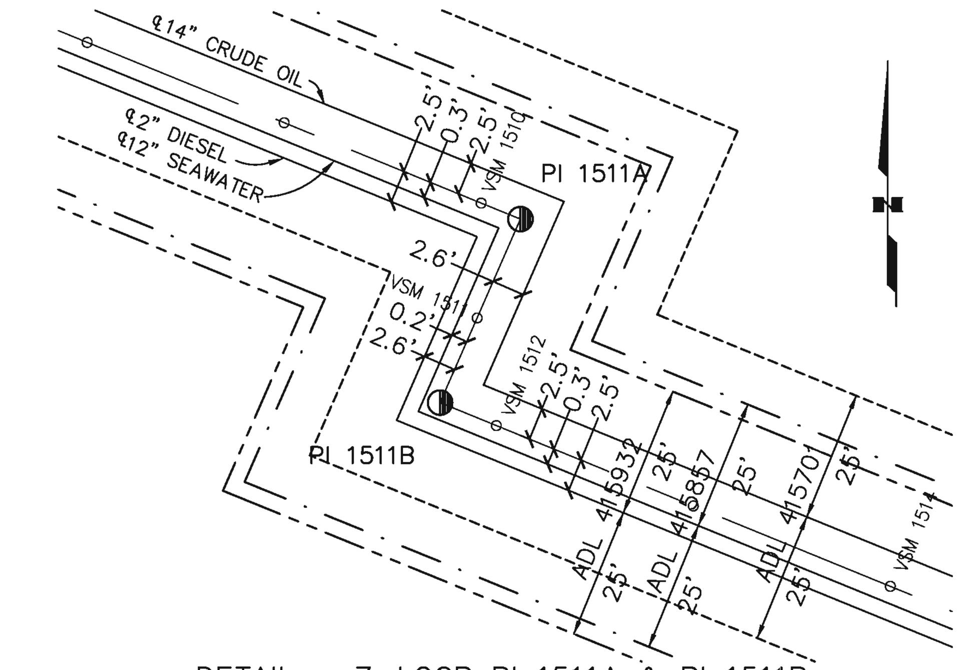

DETAIL – Z-LOOP PI 1400A & PI 1400B
N.T.S.




DETAIL – Z-LOOP PI 1456A & PI 1456B
N.T.S.




DETAIL – PI 22
N.T.S.




DETAIL – Z-LOOP PI 1511A & PI 1511B
N.T.S.


1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

## LEGEND

| | |
|---|---|
| ◑ | SET 3 1/4" ALUMINUM CAP ON 5/8"x30" REBAR |
| - - - - - | 50' WIDE ADL 415701 14"ø CRUDE OIL LINE |
| — · — | 50' WIDE ADL 415857 12"ø SEAWATER LINE |
| — — — | 50' WIDE ADL 415932 2"ø DIESEL LINE |
| VSM 0122 o | VSM |
| VSM 0101A o-o | VSM ANCHOR |

| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING | RM #1 | DESC. | RM #2 | DESC. |
|---|---|---|---|---|---|---|---|---|
| 1343A | 70°13'58.614"N | 150°37'39.111"W | 5,935,146.924 | 422,264.376 | 13.59' | VSM 1342 | 27.05' | VSM 1343 |
| 1343B | 70°13'58.023"N | 150°37'39.082"W | 5,935,086.796 | 422,264.749 | 32.42' | VSM 1343 | 18.29' | VSM 1344 |
| 1400A | 70°14'00.044"N | 150°35'54.424"W | 5,935,255.949 | 425,867.952 | 13.50' | VSM 1399 | 27.22' | VSM 1400 |
| 1400B | 70°13'59.454"N | 150°35'54.401"W | 5,935,195.992 | 425,868.139 | 32.12' | VSM 1400 | 18.56' | VSM 1401 |
| 1456A | 70°14'01.424"N | 150°34'11.630"W | 5,935,362.311 | 429,406.218 | 13.06' | VSM 1455 | 27.85' | VSM 1456 |
| 1456B | 70°14'00.827"N | 150°34'11.577"W | 5,935,301.679 | 429,407.477 | 32.13' | VSM 1456 | 18.02' | VSM 1457 |
| PI 22 | 70°14'01.830"N | 150°33'18.945"W | 5,935,386.845 | 431,219.381 | 10.26' | VSM 1485B | 55.05' | VSM 1486 |
| 1511A | 70°13'55.911"N | 150°32'34.957"W | 5,934,771.494 | 432,727.559 | 13.16' | VSM 1510 | 28.85' | VSM 1511 |
| 1511B | 70°13'55.357"N | 150°32'35.655"W | 5,934,715.398 | 432,703.018 | 31.70' | VSM 1511 | 17.93' | VSM 1512 |

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01<br>Ending 4/12/01 | LCMF Incorporated<br>139 E. 51St.<br>Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

# DIVISION OF MINING, LAND AND WATER

ANCHORAGE, ALASKA

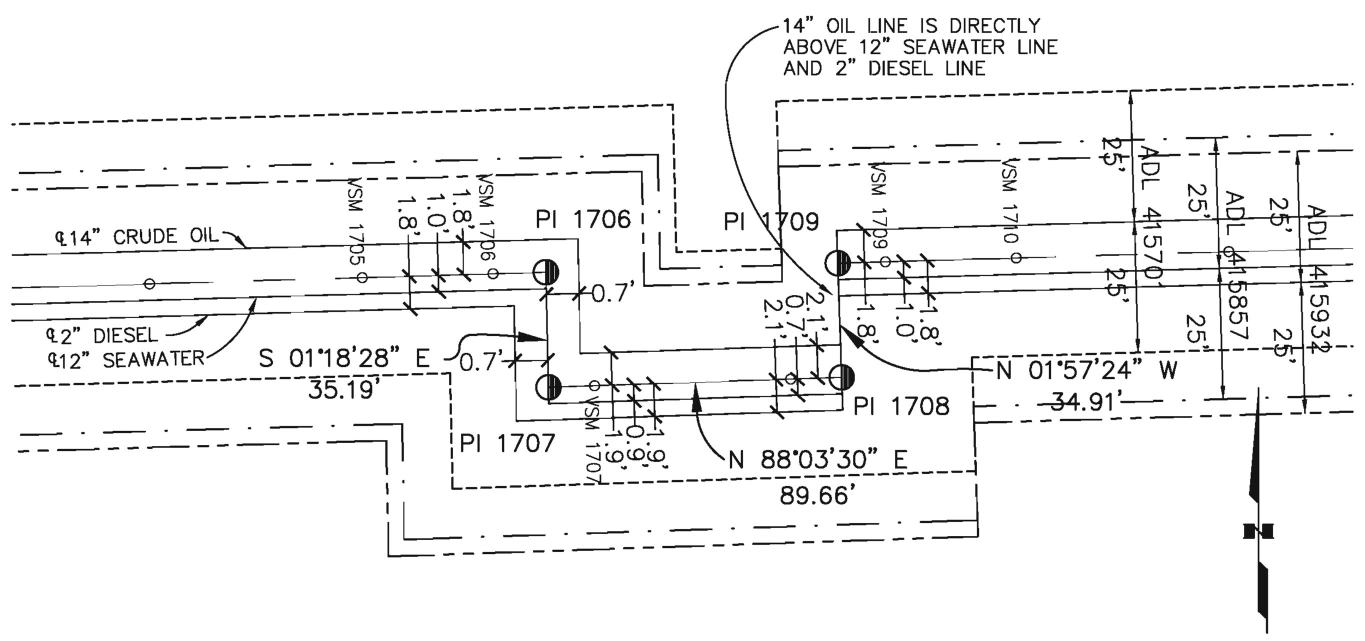
# RECORD OF SURVEY

## OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

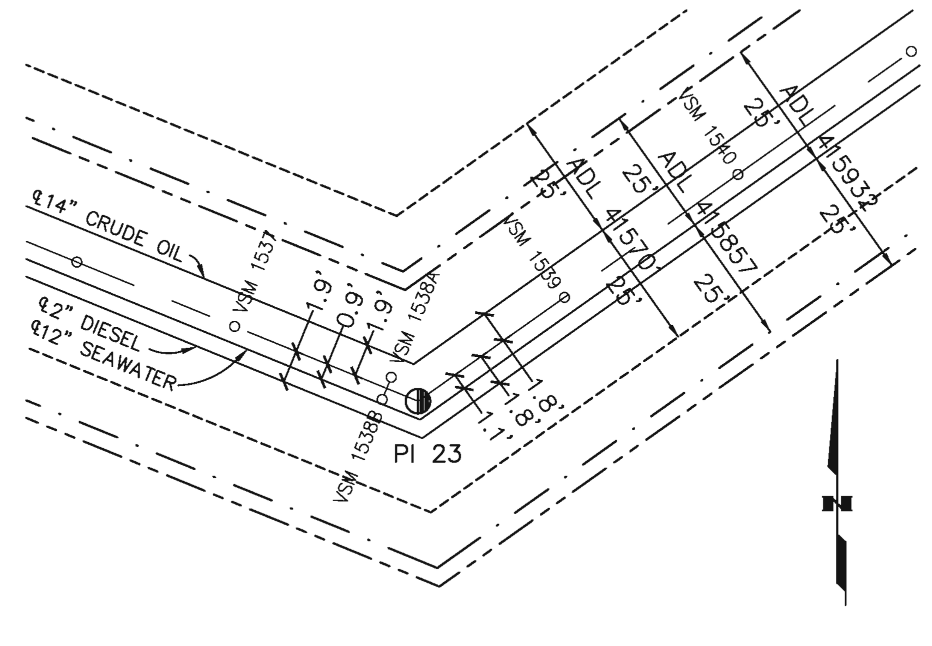
LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

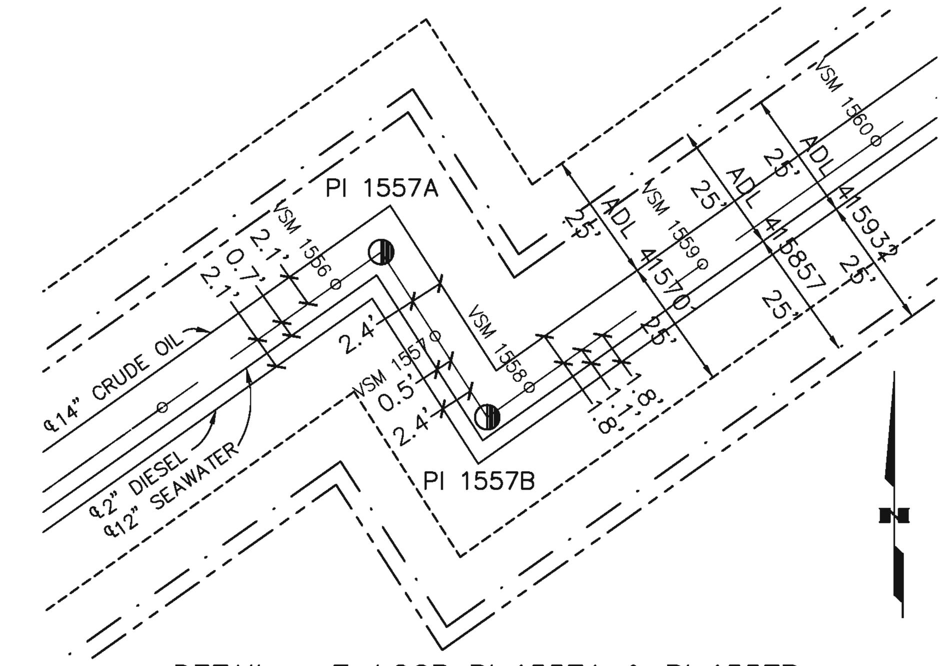
| | | | |
|---|---|---|---|
| DRAWN BY CEZ<br>DATE 5/14/03 | APPROVAL RECOMMENDED<br>Statewide Platting Supervisor    Date | | |
| SCALE 1"=400' | CHECKED APH | SHEET 13 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |




DETAIL – VERTICAL LOOP #4 PI 1706, PI 1707, PI 1708 & PI 1709
N.T.S.




DETAIL – PI 23
N.T.S.




DETAIL – Z-LOOP PI 1557A & PI 1557B
N.T.S.

| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING | RM #1 | DESC. | RM #2 | DESC. |
|---|---|---|---|---|---|---|---|---|
| PI 23 | 70°13'49.253"N | 150°31'50.345"W | 5,934,081.093 | 434,256.752 | 11.15' | VSM 1538A | 57.64' | VSM 1539 |
| 1557A | 70°13'56.034"N | 150°31'22.627"W | 5,934,762.190 | 435,216.543 | 13.57' | VSM 1556 | 27.56' | VSM 1557 |
| 1557B | 70°13'55.540"N | 150°31'21.673"W | 5,934,711.736 | 435,248.959 | 31.79' | VSM 1557 | 18.65' | VSM 1558 |
| PI 24 | 70°14'02.595"N | 150°30'52.859"W | 5,935,420.444 | 436,246.522 | 8.63' | VSM 1577A | 56.31' | VSM 1578 |
| 1604A | 70°14'03.224"N | 150°30'03.614"W | 5,935,470.343 | 437,941.449 | 13.91' | VSM 1603 | 27.68' | VSM 1604 |
| 1604B | 70°14'02.634"N | 150°30'03.641"W | 5,935,410.309 | 437,940.040 | 31.70' | VSM 1604 | 18.57' | VSM 1605 |
| 1657A | 70°14'03.871"N | 150°28'26.431"W | 5,935,509.308 | 441,285.781 | 12.77' | VSM 1656 | 28.23' | VSM 1657 |
| 1657B | 70°14'03.273"N | 150°28'26.409"W | 5,935,448.444 | 441,286.050 | 32.01' | VSM 1657 | 18.11' | VSM 1658 |
| 1706 | 70°14'04.412"N | 150°26'55.545"W | 5,935,540.626 | 444,413.296 | 15.97' | VSM 1706 | 35.38' | VSM 1707 |
| 1707 | 70°14'04.066"N | 150°26'55.514"W | 5,935,505.450 | 444,414.099 | 40.17' | VSM 1706 | 15.31' | VSM 1707 |
| 1708 | 70°14'04.103"N | 150°26'52.910"W | 5,935,508.488 | 444,503.710 | 13.97' | VSM 1708 | 39.38' | VSM 1709 |
| 1709 | 70°14'04.446"N | 150°26'52.952"W | 5,935,543.377 | 444,502.518 | 34.97' | VSM 1708 | 15.09' | VSM 1709 |
| 1726 | 70°14'04.839"N | 150°26'21.428"W | 5,935,575.402 | 445,587.472 | 14.70' | VSM 1726 | 19.38' | VSM 1727 |
| 1727 | 70°14'04.682"N | 150°26'21.397"W | 5,935,559.453 | 445,588.403 | 23.03' | VSM 1726 | 14.26' | VSM 1727 |
| 1728 | 70°14'04.704"N | 150°26'18.769"W | 5,935,561.092 | 445,678.842 | 15.92' | VSM 1728 | 23.11' | VSM 1729 |
| 1729 | 70°14'04.870"N | 150°26'18.825"W | 5,935,577.955 | 445,677.032 | 19.10' | VSM 1728 | 15.17' | VSM 1729 |


1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01 | LCMF Incorporated |
| Ending 4/12/01 | 139 E. 51St.<br>Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

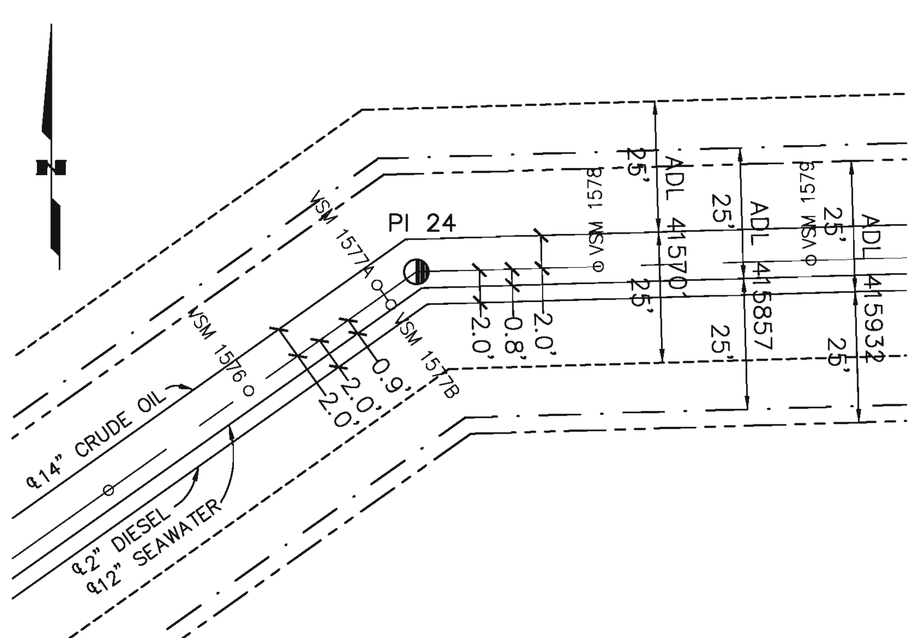
## RECORD OF SURVEY

OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

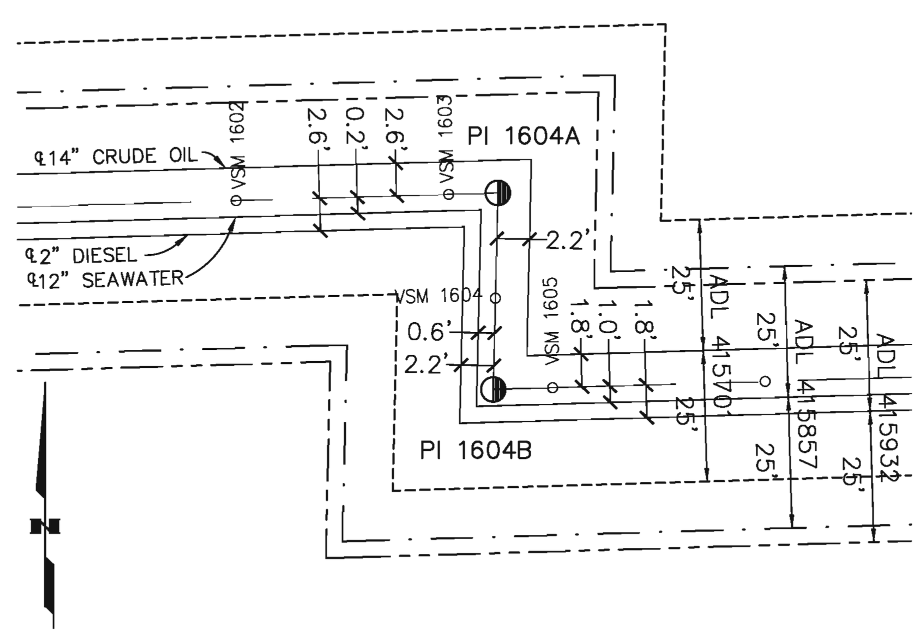
LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.;
SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.;
SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.;
SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

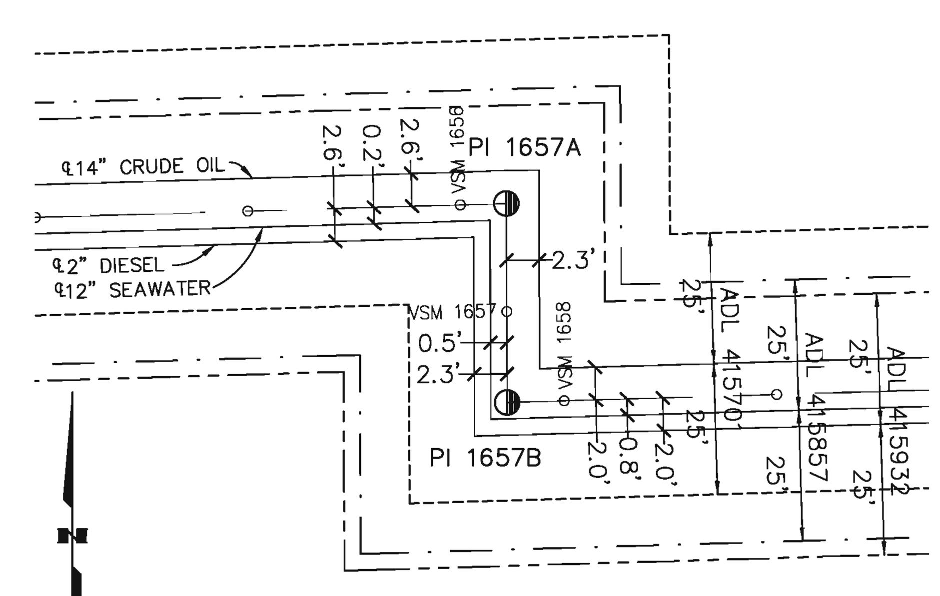
| DRAWN BY CEZ | APPROVAL RECOMMENDED | | |
|---|---|---|---|
| DATE 5/14/03 | Statewide Platting Supervisor | | Date |
| SCALE 1"=400' | CHECKED APH | SHEET 14 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |



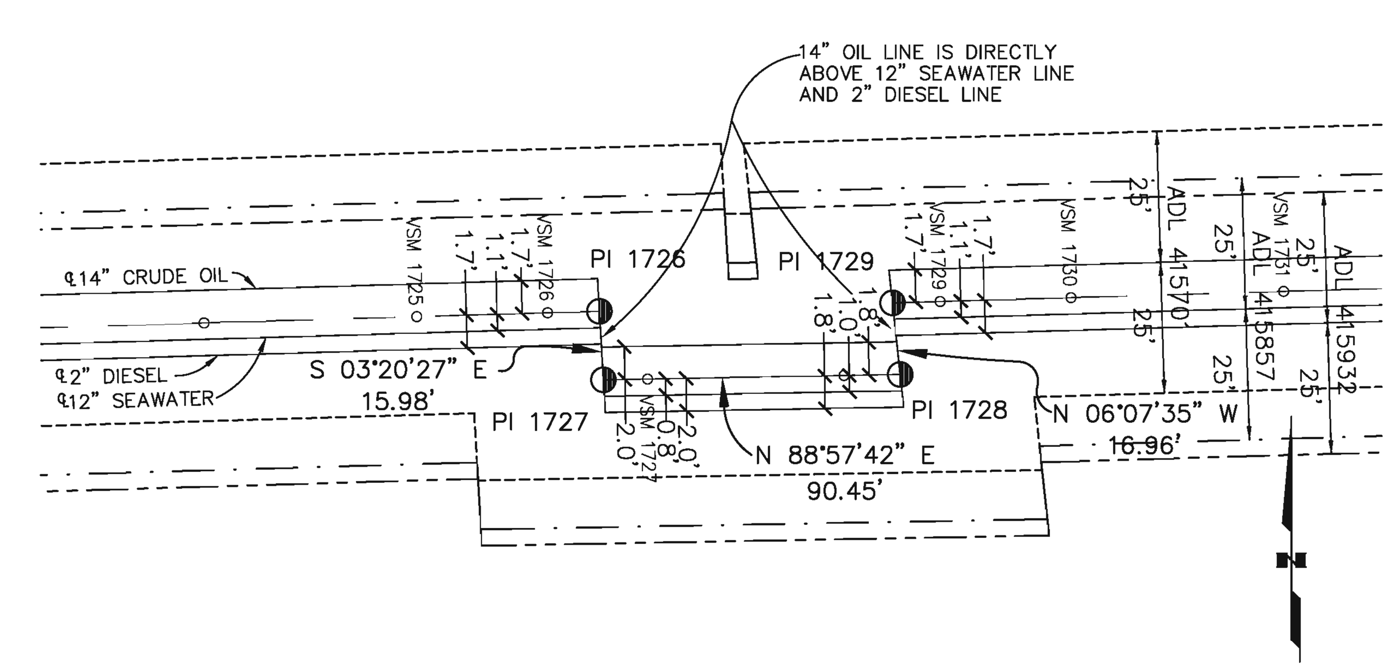

DETAIL – PI 24
N.T.S.




DETAIL – Z-LOOP PI 1604A & PI 1604B
N.T.S.



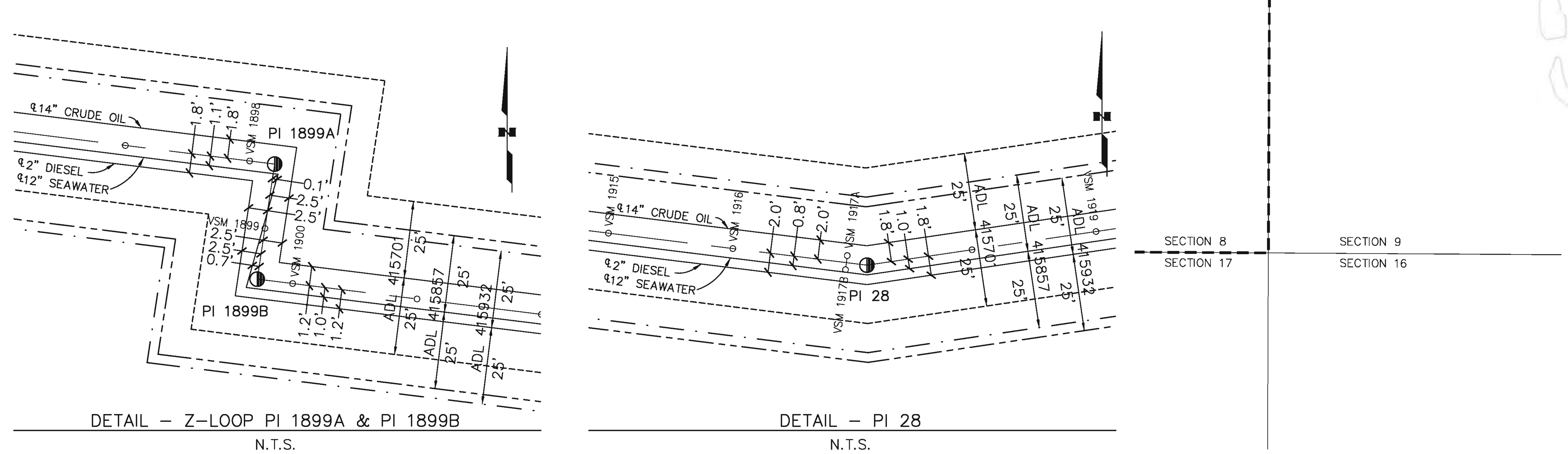

DETAIL – Z-LOOP PI 1657A & PI 1657B
N.T.S.




DETAIL – VERTICAL LOOP #5 PI 1726, PI 1727, PI 1728 & PI 1729
N.T.S.



1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES




| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING | RM #1 | DESC. | RM #2 | DESC. |
|---|---|---|---|---|---|---|---|---|
| PI 26 | 70°14'05.101"N | 150°26'00.121"W | 5,935,596.876 | 446,320.742 | 11.44' | VSM 1739A | 55.79' | VSM 1740 |
| 1760A | 70°14'08.191"N | 150°25'23.322"W | 5,935,902.108 | 447,589.055 | 13.22' | VSM 1759 | 27.47' | VSM 1760 |
| 1760B | 70°14'07.610"N | 150°25'22.953"W | 5,935,842.903 | 447,601.352 | 32.40' | VSM 1760 | 18.32' | VSM 1761 |
| 1808A | 70°14'14.763"N | 150°23'57.704"W | 5,936,550.317 | 450,539.163 | 13.17' | VSM 1807 | 27.41' | VSM 1808 |
| 1808B | 70°14'14.185"N | 150°23'57.327"W | 5,936,491.479 | 450,551.756 | 32.11' | VSM 1808 | 18.01' | VSM 1809 |
| 1855A | 70°14'21.110"N | 150°22'34.635"W | 5,937,177.425 | 453,400.899 | 13.13' | VSM 1854 | 27.38' | VSM 1855 |
| 1855B | 70°14'20.533"N | 150°22'34.257"W | 5,937,118.663 | 453,413.543 | 31.99' | VSM 1855 | 17.69' | VSM 1856 |
| PI 27 | 70°14'24.158"N | 150°21'50.985"W | 5,937,478.120 | 454,904.296 | 8.75' | VSM 1880B | 56.21' | VSM 1881 |
| 1899A | 70°14'22.795"N | 150°21'17.061"W | 5,937,332.634 | 456,070.392 | 13.07' | VSM 1898 | 27.27' | VSM 1899 |
| 1899B | 70°14'22.207"N | 150°21'17.314"W | 5,937,272.904 | 456,061.357 | 32.48' | VSM 1899 | 18.25' | VSM 1900 |
| PI 28 | 70°14'20.903"N | 150°20'44.732"W | 5,937,133.893 | 457,181.375 | 10.98' | VSM 1917A | 56.14' | VSM 1918 |

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01<br>Ending 4/12/01 | LCMF Incorporated<br>139 E. 51St.<br>Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

## DIVISION OF MINING, LAND AND WATER

ANCHORAGE, ALASKA

# RECORD OF SURVEY

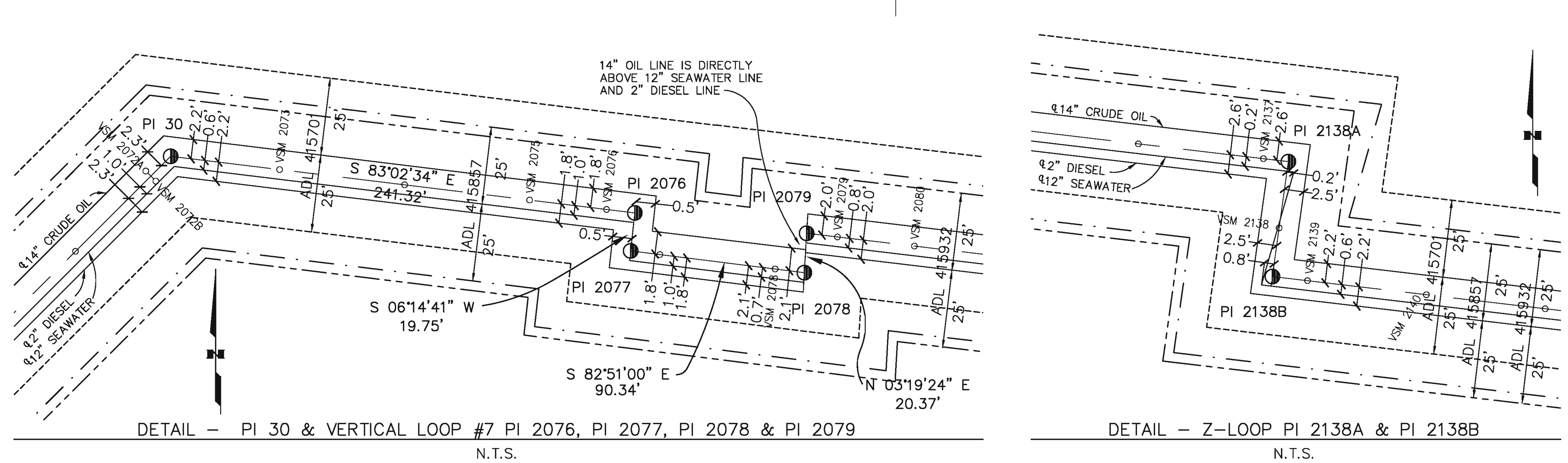
OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.;
SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.;
SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.;
SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.;
AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E.,
UMIAT MERIDIAN, ALASKA

CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

| | | | |
|---|---|---|---|
| DRAWN BY CEZ<br>DATE 5/14/03 | APPROVAL RECOMMENDED<br>Statewide Platting Supervisor   Date | | |
| SCALE 1"=400' | CHECKED APH | SHEET 15 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |


1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES




| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING | RM #1 | DESC. | RM #2 | DESC. |
|---|---|---|---|---|---|---|---|---|
| 1941A | 70°14'23.128"N | 150°20'01.633"W | 5,937,351.889 | 458,665.216 | 12.91' | VSM 1940 | 28.07' | VSM 1941 |
| 1941B | 70°14'22.532"N | 150°20'01.412"W | 5,937,291.191 | 458,672.492 | 32.40' | VSM 1941 | 18.18' | VSM 1942 |
| 2000A | 70°14'27.961"N | 150°18'15.807"W | 5,937,824.155 | 462,307.939 | 13.29' | VSM 1999 | 27.35' | VSM 2000 |
| 2000B | 70°14'27.375"N | 150°18'15.588"W | 5,937,764.481 | 462,315.186 | 32.05' | VSM 2000 | 17.71' | VSM 2001 |
| 2022 | 70°14'29.402"N | 150°17'36.096"W | 5,937,963.920 | 463,674.541 | 15.75' | VSM 2022 | 31.72' | VSM 2023 |
| 2023 | 70°14'29.090"N | 150°17'35.983"W | 5,937,932.204 | 463,678.306 | 36.73' | VSM 2022 | 14.62' | VSM 2023 |
| 2024 | 70°14'29.217"N | 150°17'33.370"W | 5,937,944.660 | 463,768.242 | 15.84' | VSM 2024 | 32.20' | PI 2025 |
| 2025 | 70°14'29.529"N | 150°17'33.534"W | 5,937,976.370 | 463,762.756 | 31.81' | VSM 2024 | 14.79' | VSM 2025 |
| PI 29 | 70°14'30.070"N | 150°17'23.040"W | 5,938,029.714 | 464,123.950 | 10.71' | VSM 2031A | 55.67' | VSM 2032 |
| 2054A | 70°14'39.893"N | 150°16'54.195"W | 5,939,023.671 | 465,120.724 | 12.92' | VSM 2053 | 27.03' | VSM 2054 |
| 2054B | 70°14'39.469"N | 150°16'52.978"W | 5,938,980.412 | 465,162.364 | 32.41' | VSM 2054 | 17.90' | VSM 2055 |
| PI 30 | 70°14'46.976"N | 150°16'30.981"W | 5,939,740.126 | 465,922.331 | 9.05' | VSM 2072A | 55.65' | VSM 2073 |
| 2076 | 70°14'46.699"N | 150°16'24.011"W | 5,939,710.895 | 466,161.872 | 15.08' | VSM 2076 | 21.97' | VSM 2077 |
| 2077 | 70°14'46.506"N | 150°16'24.071"W | 5,939,691.265 | 466,159.724 | 26.36' | VSM 2076 | 14.31' | VSM 2077 |
| 2078 | 70°14'46.399"N | 150°16'21.463"W | 5,939,680.020 | 466,249.366 | 15.58' | VSM 2078 | 26.06' | VSM 2079 |
| 2079 | 70°14'46.599"N | 150°16'21.431"W | 5,939,700.358 | 466,250.547 | 21.77' | VSM 2078 | 15.08' | VSM 2079 |
| 2094A | 70°14'45.579"N | 150°15'55.054"W | 5,939,592.591 | 467,157.148 | 12.50' | VSM 2093 | 27.14' | VSM 2094 |
| 2094B | 70°14'44.992"N | 150°15'55.275"W | 5,939,533.017 | 467,149.287 | 32.41' | VSM 2094 | 17.97' | VSM 2095 |
| 2138A | 70°14'41.915"N | 150°14'35.483"W | 5,939,208.752 | 469,891.965 | 13.27' | VSM 2137 | 27.38' | VSM 2138 |
| 2138B | 70°14'41.331"N | 150°14'35.716"W | 5,939,149.393 | 469,883.718 | 31.85' | VSM 2138 | 17.49' | VSM 2139 |

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01<br>Ending 4/12/01 | LCMF Incorporated<br>139 E. 51St.<br>Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

# RECORD OF SURVEY

## OF THE ALPINE TO KUPARUK CPF–2 OVERLAND PIPELINE

LOCATED WITHIN
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CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

| DRAWN BY CEZ<br>DATE 5/14/03 | APPROVAL RECOMMENDED<br>Statewide Platting Supervisor / Date | | |
|---|---|---|---|
| SCALE 1"=400' | CHECKED APH | SHEET 16 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |


1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING | RM #1 | DESC. | RM #2 | DESC. |
|---|---|---|---|---|---|---|---|---|
| PI 31 | 70°14'39.922"N | 150°13'59.241"W | 5,939,001.212 | 471,137.563 | 11.65' | VSM 2159A | 56.73' | VSM 2160 |
| 2187A | 70°14'47.299"N | 150°13'12.920"W | 5,939,745.232 | 472,733.284 | 13.96' | VSM 2186 | 27.27' | VSM 2187 |
| 2187B | 70°14'46.753"N | 150°13'12.253"W | 5,939,689.694 | 472,756.022 | 32.06' | VSM 2187 | 18.64' | VSM 2188 |
| 2241A | 70°15'01.038"N | 150°11'42.433"W | 5,941,131.483 | 475,849.403 | 13.82' | VSM 2240 | 27.17' | VSM 2241 |
| 2241B | 70°15'00.491"N | 150°11'41.761"W | 5,941,075.791 | 475,872.329 | 32.44' | VSM 2241 | 18.66' | VSM 2242 |
| 2294A | 70°15'14.489"N | 150°10'13.623"W | 5,942,489.846 | 478,906.635 | 13.51' | VSM 2293 | 27.00' | VSM 2294 |
| 2294B | 70°15'13.943"N | 150°10'12.942"W | 5,942,434.227 | 478,929.878 | 32.64' | VSM 2294 | 18.71' | VSM 2295 |
| 2348A | 70°15'28.202"N | 150°08'43.095"W | 5,943,875.887 | 482,021.877 | 12.64' | VSM 2347 | 27.02' | VSM 2348 |
| 2348B | 70°15'27.662"N | 150°08'42.381"W | 5,943,820.992 | 482,046.281 | 32.51' | VSM 2348 | 17.83' | VSM 2349 |

DATE OF SURVEY
Beginning 3/01/01
Ending 4/12/01

NAME OF SURVEYOR
LCMF Incorporated
139 E. 51St.
Anch., Alaska 99503

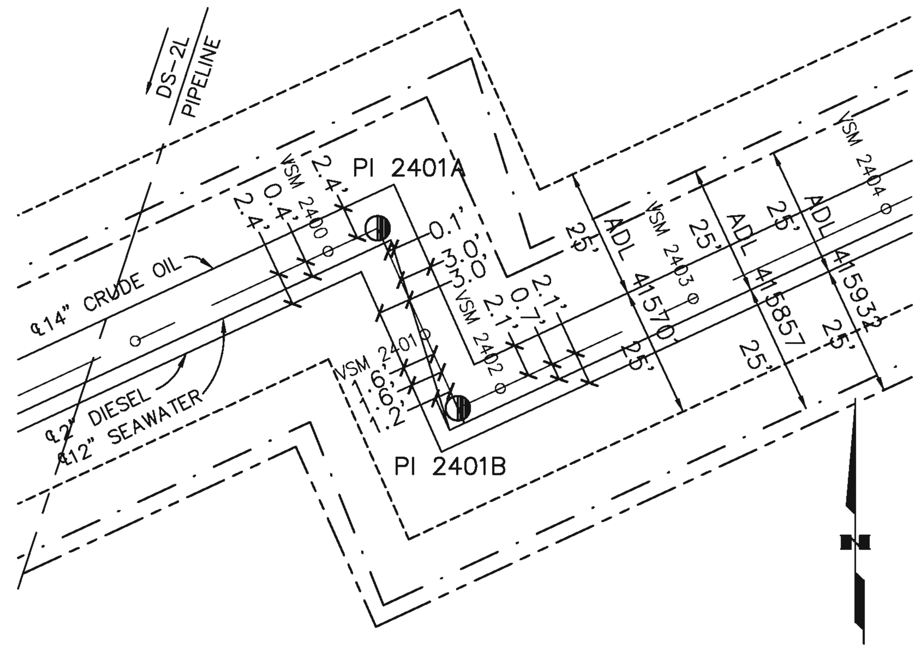
STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
## DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

# RECORD OF SURVEY
OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

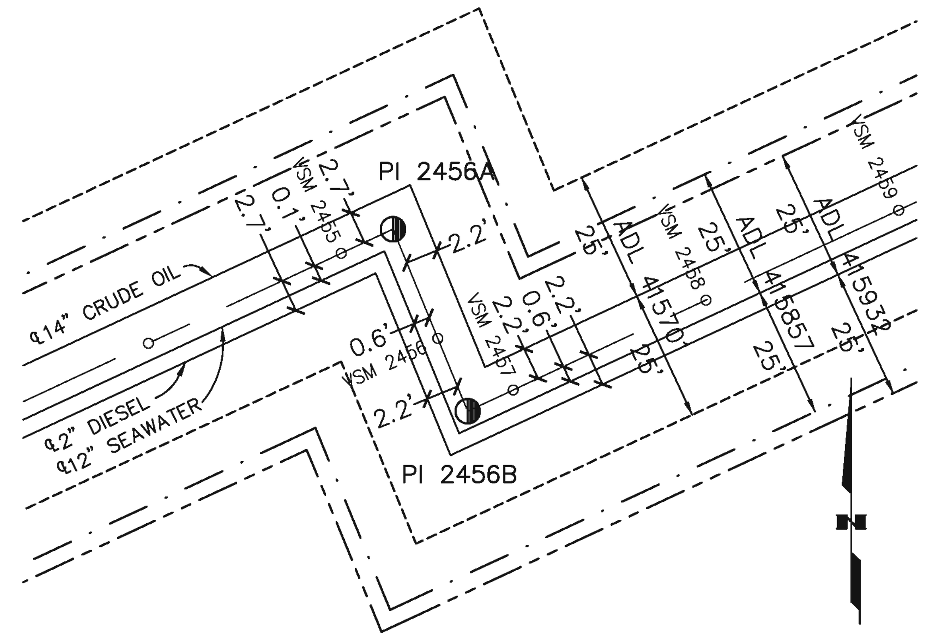
LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

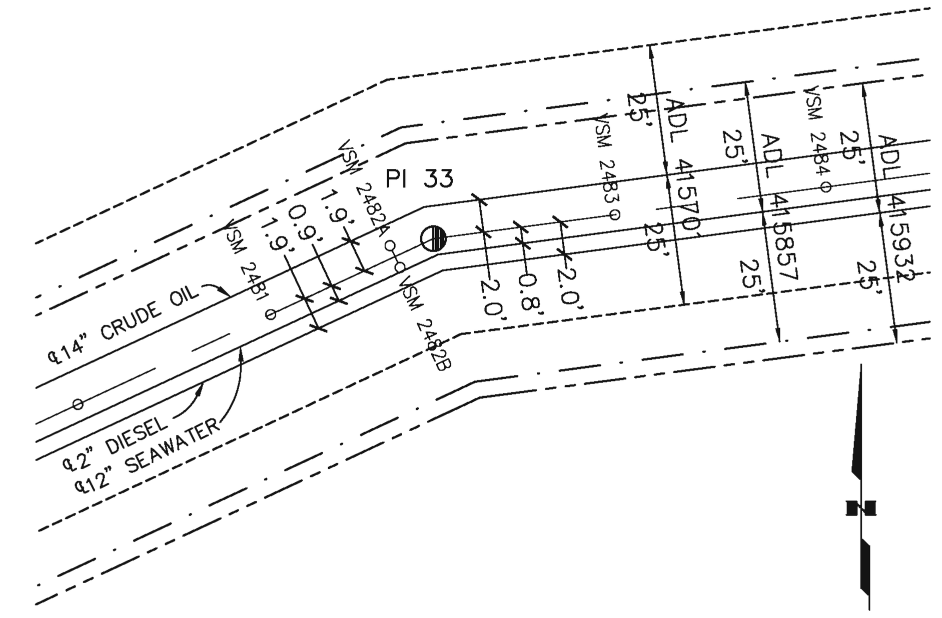
DRAWN BY CEZ
DATE 5/14/03
APPROVAL RECOMMENDED
Statewide Platting Supervisor — Date
SCALE 1"=400'
CHECKED APH
SHEET 17 of 21
FILE NO. LOCATED WITHIN EPF20020040A



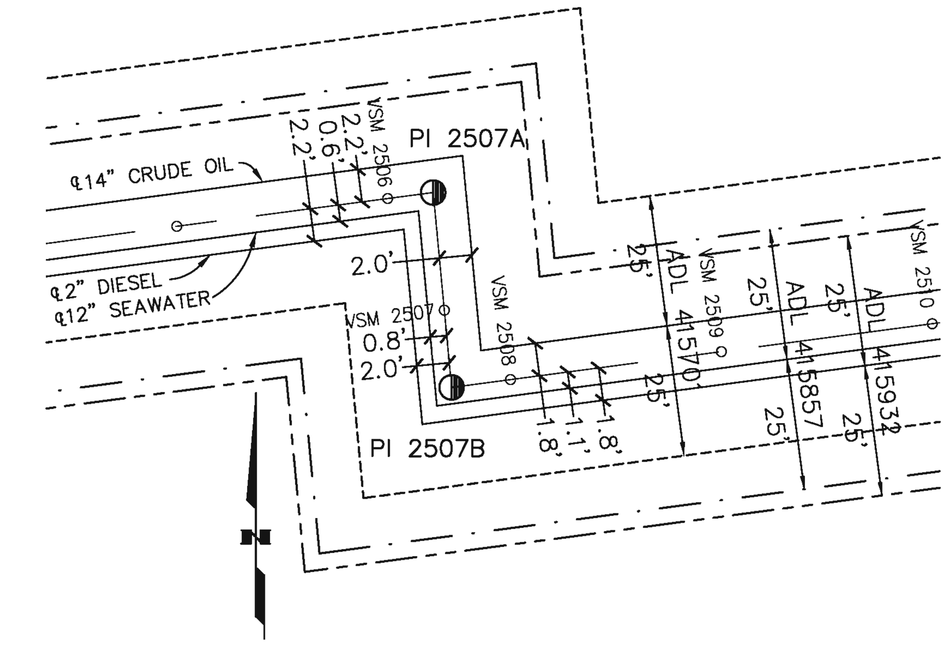

DETAIL – Z-LOOP PI 2401A & PI 2401B
N.T.S.




DETAIL – Z-LOOP PI 2456A & PI 2456B
N.T.S.




DETAIL – PI 33
N.T.S.




DETAIL – Z-LOOP PI 2507A & PI 2507B
N.T.S.


| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING | RM #1 | DESC. | RM #2 | DESC. |
|---|---|---|---|---|---|---|---|---|
| 2401A | 70°15'41.789"N | 150°07'13.217"W | 5,945,250.527 | 485,113.589 | 13.12' | VSM 2400 | 27.09' | VSM 2401 |
| 2401B | 70°15'41.248"N | 150°07'12.501"W | 5,945,195.485 | 485,138.096 | 32.46' | VSM 2401 | 17.70' | VSM 2402 |
| 2456A | 70°15'55.753"N | 150°05'40.865"W | 5,946,664.590 | 488,289.244 | 14.13' | VSM 2455 | 27.19' | VSM 2456 |
| 2456B | 70°15'55.206"N | 150°05'40.197"W | 5,946,608.977 | 488,312.093 | 32.21' | VSM 2456 | 18.49' | VSM 2457 |
| PI 33 | 70°16'02.003"N | 150°04'57.220"W | 5,947,297.845 | 489,789.557 | 9.20' | VSM 2482B | 56.34' | VSM 2483 |
| 2507A | 70°16'04.031"N | 150°04'12.061"W | 5,947,502.099 | 491,341.149 | 13.59' | VSM 2506 | 26.74' | VSM 2507 |
| 2507B | 70°16'03.446"N | 150°04'11.895"W | 5,947,442.565 | 491,346.793 | 32.42' | VSM 2507 | 18.41' | VSM 2508 |

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01<br>Ending 4/12/01 | LCMF Incorporated<br>139 E. 51St.<br>Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

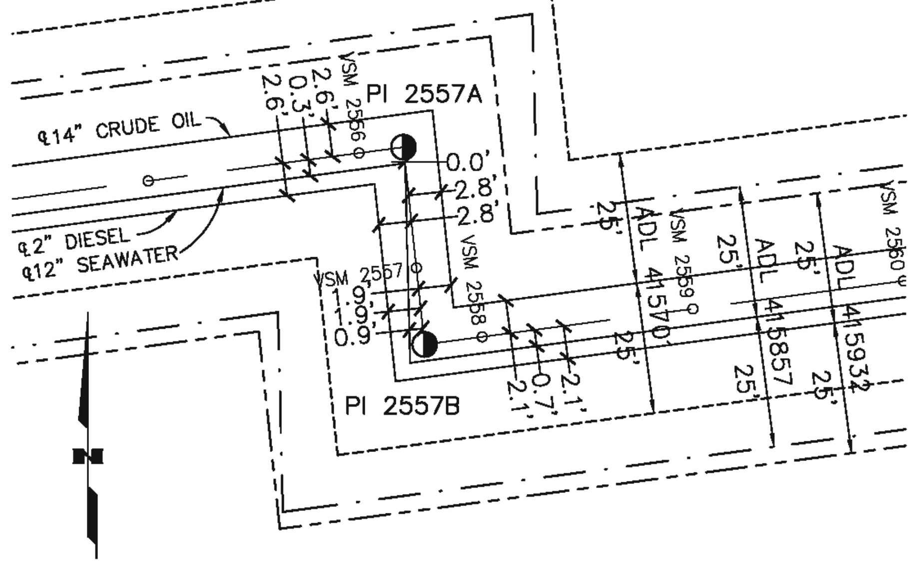
# RECORD OF SURVEY

OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

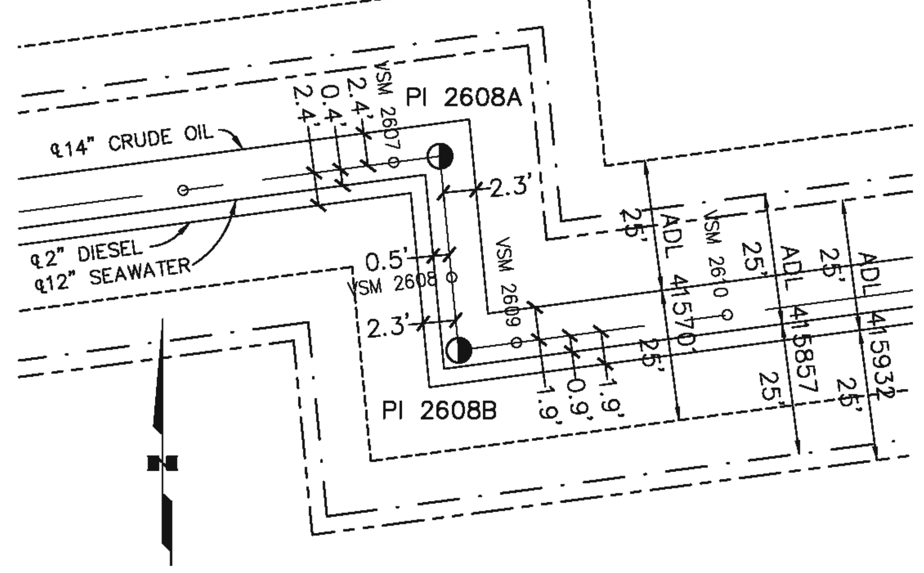
LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

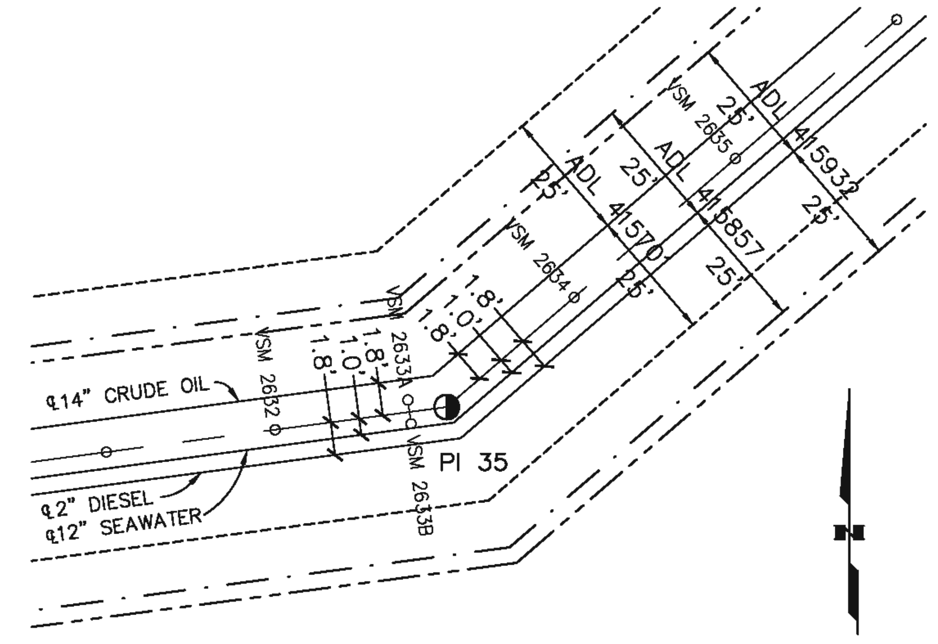
| DRAWN BY | APPROVAL RECOMMENDED | | | |
|---|---|---|---|---|
| CEZ<br>DATE 5/14/03 | Statewide Platting Supervisor | | | Date |
| SCALE<br>1"=400' | CHECKED<br>APH | SHEET<br>18 of 21 | FILE NO. LOCATED WITHIN<br>EPF20020040A | |



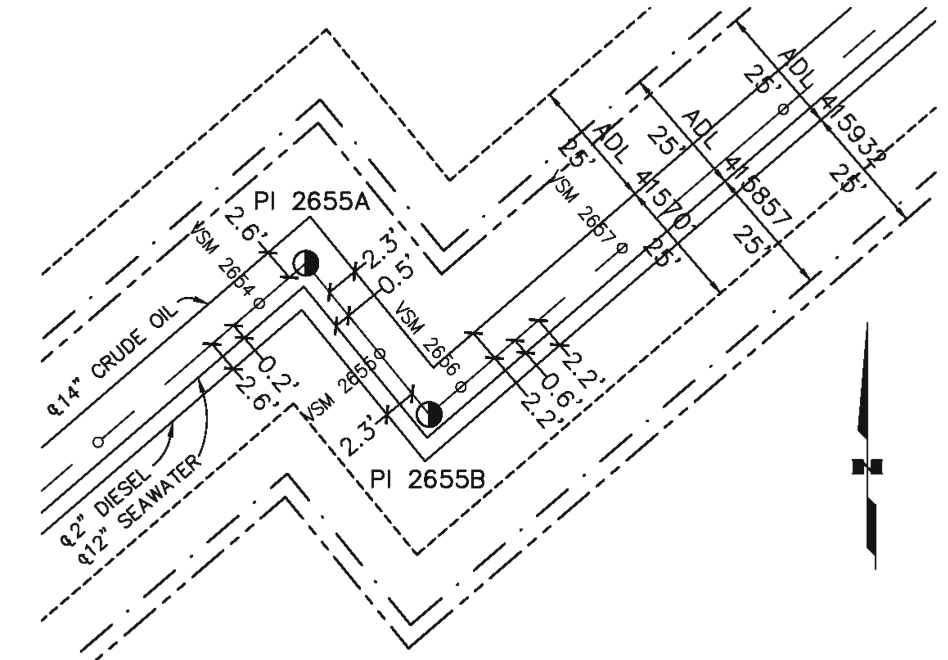
DETAIL – Z-LOOP PI 2557A & PI 2557B
N.T.S.



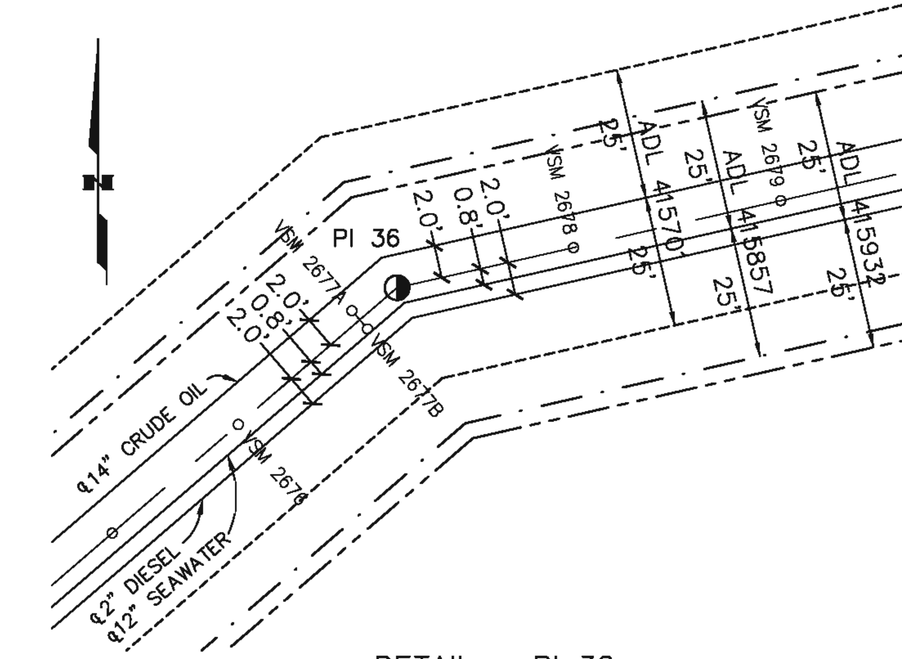
DETAIL – Z-LOOP PI 2608A & PI 2608B
N.T.S.



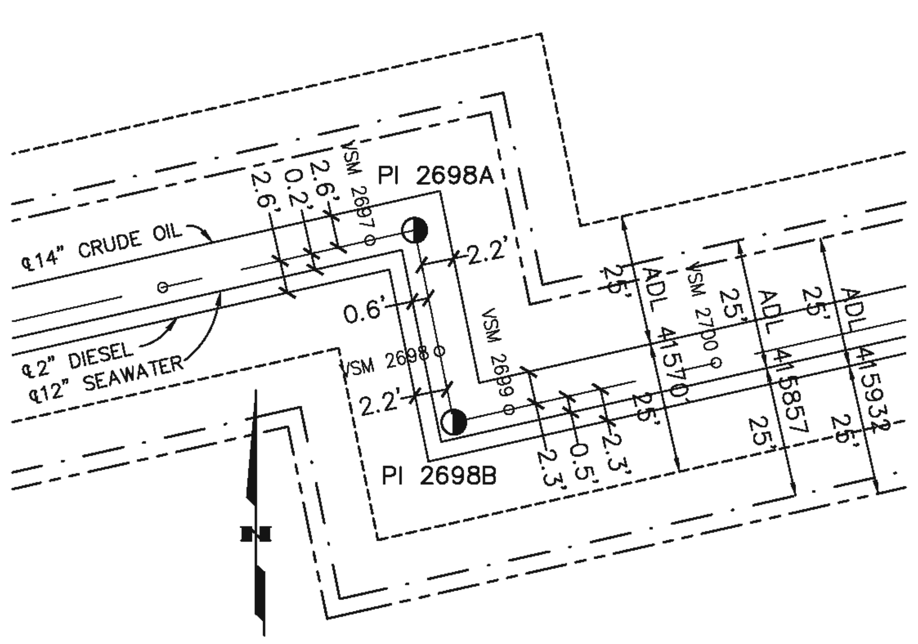
DETAIL – PI 35
N.T.S.



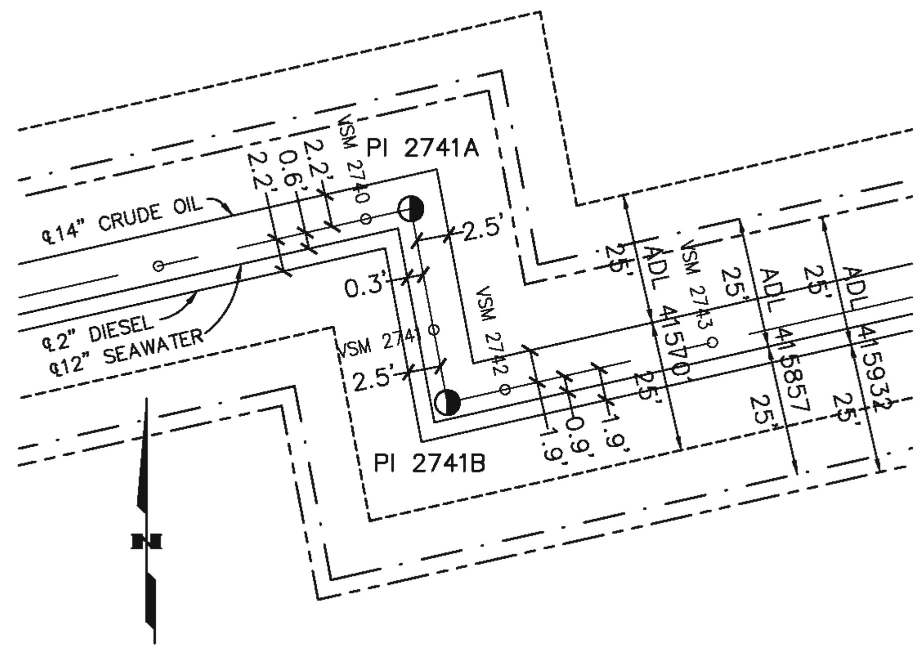
DETAIL – Z-LOOP PI 2655A & PI 2655B
N.T.S.



DETAIL – PI 36
N.T.S.



DETAIL – Z-LOOP PI 2698A & PI 2698B
N.T.S.



DETAIL – Z-LOOP PI 2741A & PI 2741B
N.T.S.


| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING | RM #1 | DESC. | RM #2 | DESC. |
|---|---|---|---|---|---|---|---|---|
| 2557A | 70°16'07.542"N | 150°02'40.972"W | 5,947,856.061 | 494,470.540 | 13.31' | VSM 2556 | 27.35' | VSM 2557 |
| 2557B | 70°16'06.949"N | 150°02'40.782"W | 5,947,795.827 | 494,476.996 | 32.53' | VSM 2557 | 17.97' | VSM 2558 |
| 2608A | 70°16'11.075"N | 150°01'08.893"W | 5,948,213.607 | 497,633.585 | 13.82' | VSM 2607 | 27.24' | VSM 2608 |
| 2608B | 70°16'10.491"N | 150°01'08.726"W | 5,948,154.292 | 497,639.332 | 31.63' | VSM 2608 | 18.03' | VSM 2609 |
| PI 35 | 70°16'12.466"N | 150°00'24.581"W | 5,948,354.766 | 499,155.669 | 11.23' | VSM 2633A | 56.80' | VSM 2634 |
| 2655A | 70°16'21.260"N | 149°59'54.351"W | 5,949,248.744 | 500,194.021 | 13.10' | VSM 2654 | 27.21' | VSM 2655 |
| 2655B | 70°16'20.806"N | 149°59'53.254"W | 5,949,202.578 | 500,231.676 | 31.74' | VSM 2655 | 18.03' | VSM 2656 |
| PI 36 | 70°16'29.371"N | 149°59'23.808"W | 5,950,073.433 | 501,242.860 | 8.84' | VSM 2677B | 56.06' | VSM 2678 |
| 2698A | 70°16'32.205"N | 149°58'46.764"W | 5,950,361.924 | 502,514.865 | 13.09' | VSM 2697 | 27.41' | VSM 2698 |
| 2698B | 70°16'31.628"N | 149°58'46.414"W | 5,950,303.218 | 502,526.886 | 31.89' | VSM 2698 | 17.91' | VSM 2699 |
| 2741A | 70°16'37.346"N | 149°57'31.596"W | 5,950,885.933 | 505,095.702 | 13.11' | VSM 2740 | 26.90' | VSM 2741 |
| 2741B | 70°16'36.763"N | 149°57'31.272"W | 5,950,826.648 | 505,106.857 | 32.78' | VSM 2741 | 18.39' | VSM 2742 |

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01<br>Ending 4/12/01 | LCMF Incorporated<br>139 E. 51St.<br>Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
## DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

# RECORD OF SURVEY
## OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

| DRAWN BY CEZ<br>DATE 5/14/03 | APPROVAL RECOMMENDED<br>Statewide Platting Supervisor — Date | | |
|---|---|---|---|
| SCALE 1"=400' | CHECKED APH | SHEET 19 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |


1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING | RM #1 | DESC. | RM #2 | DESC. |
|---|---|---|---|---|---|---|---|---|
| 2784A | 70°16'42.602"N | 149°56'14.811"W | 5,951,422.520 | 507,731.708 | 12.83' | VSM 2783 | 26.81' | VSM 2784 |
| 2784B | 70°16'42.027"N | 149°56'14.457"W | 5,951,364.055 | 507,743.929 | 32.28' | VSM 2784 | 17.63' | VSM 2785 |
| 2826A | 70°16'47.678"N | 149°55'00.336"W | 5,951,941.586 | 510,288.048 | 13.23' | VSM 2825 | 27.41' | VSM 2826 |
| 2826B | 70°16'47.094"N | 149°54'59.998"W | 5,951,882.286 | 510,299.731 | 32.42' | VSM 2826 | 18.09' | VSM 2827 |
| PI 39 | 70°16'53.128"N | 149°53'42.209"W | 5,952,499.842 | 512,969.345 | 45.09' | VSM 2868 | 15.34' | VSM 2869 |
| 2885A | 70°17'01.448"N | 149°53'29.686"W | 5,953,346.494 | 513,397.720 | 12.79' | VSM 2884 | 24.99' | VSM 2885 |
| 2885B | 70°17'01.192"N | 149°53'28.262"W | 5,953,320.590 | 513,446.648 | 29.71' | VSM 2885 | 17.62' | VSM 2886 |
| 2890A | 70°17'02.702"N | 149°53'25.982"W | 5,953,474.174 | 513,524.655 | 17.00' | VSM 2889 | 29.46' | VSM 2890 |
| 2890B | 70°17'02.947"N | 149°53'27.419"W | 5,953,499.024 | 513,475.275 | 25.16' | VSM 2890 | 12.46' | VSM 2891 |
| PI 40 | 70°17'10.540"N | 149°53'15.929"W | 5,954,271.710 | 513,868.239 | 9.32' | VSM 2905A | 61.38' | VSM 2906 |

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01<br>Ending 4/12/01 | LCMF Incorporated<br>139 E. 51St.<br>Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

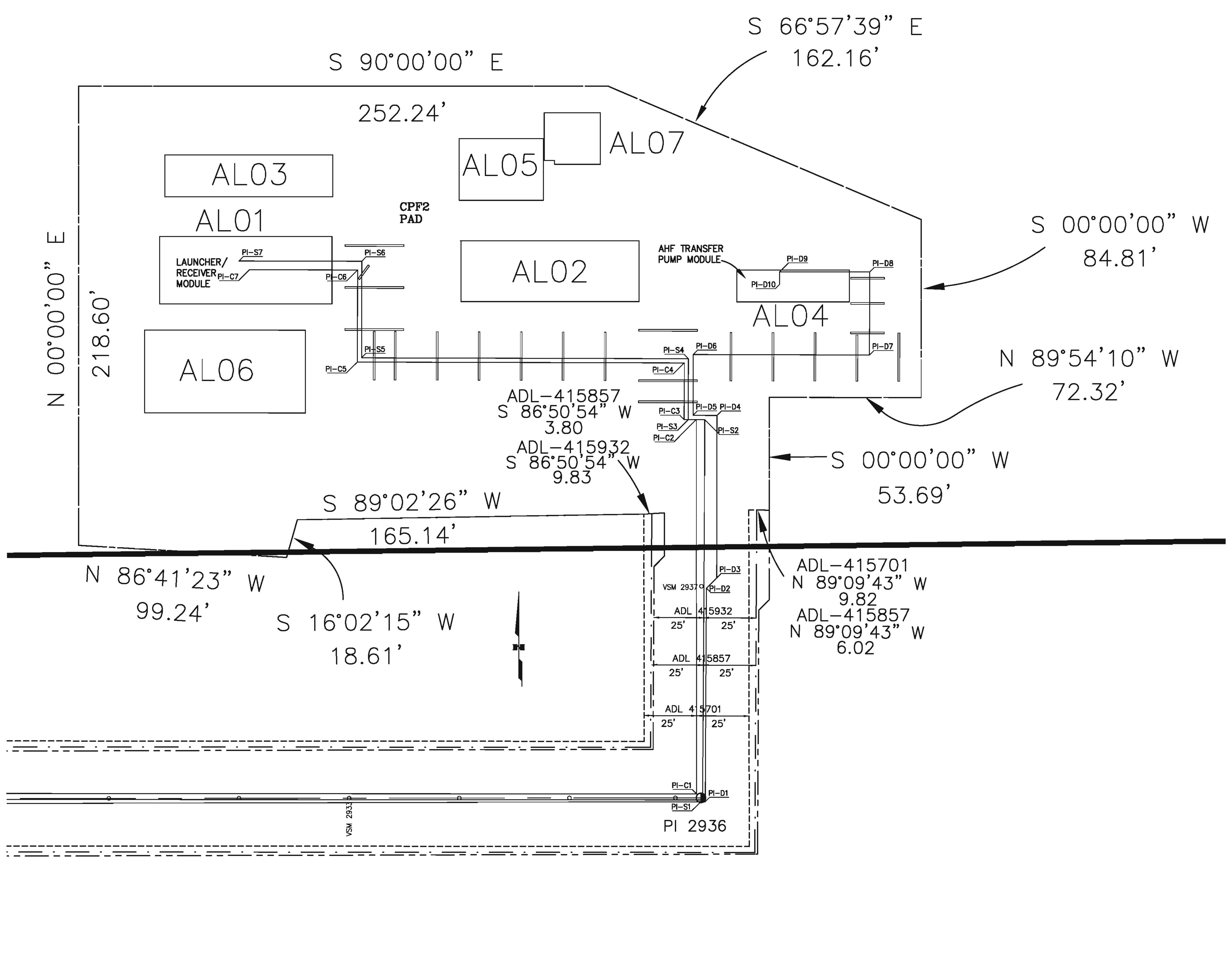
# RECORD OF SURVEY

## OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

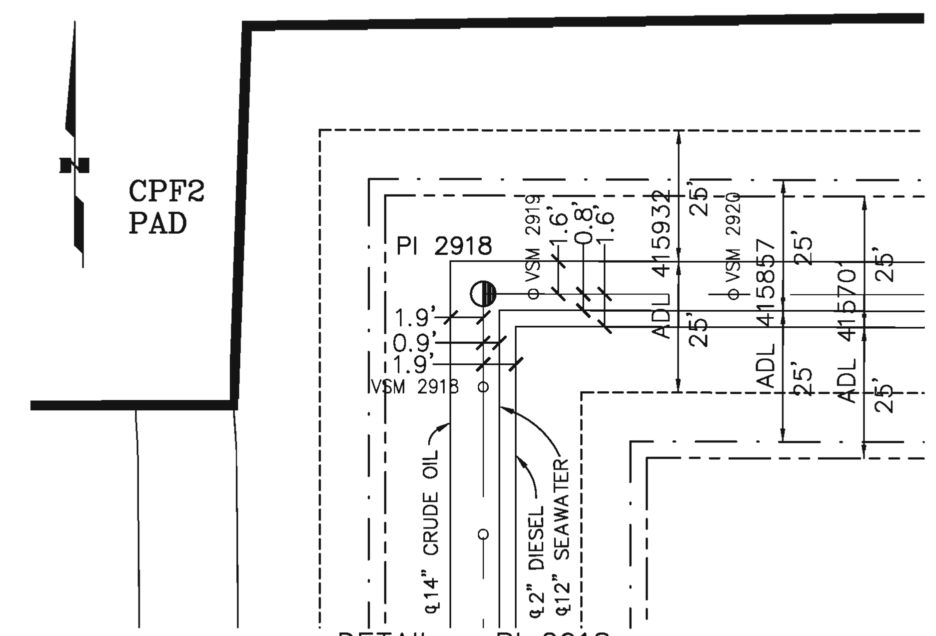
CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

| DRAWN BY CEZ<br>DATE 5/14/03 | APPROVAL RECOMMENDED<br>Statewide Platting Supervisor — Date | | |
|---|---|---|---|
| SCALE 1"=400' | CHECKED APH | SHEET 20 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |



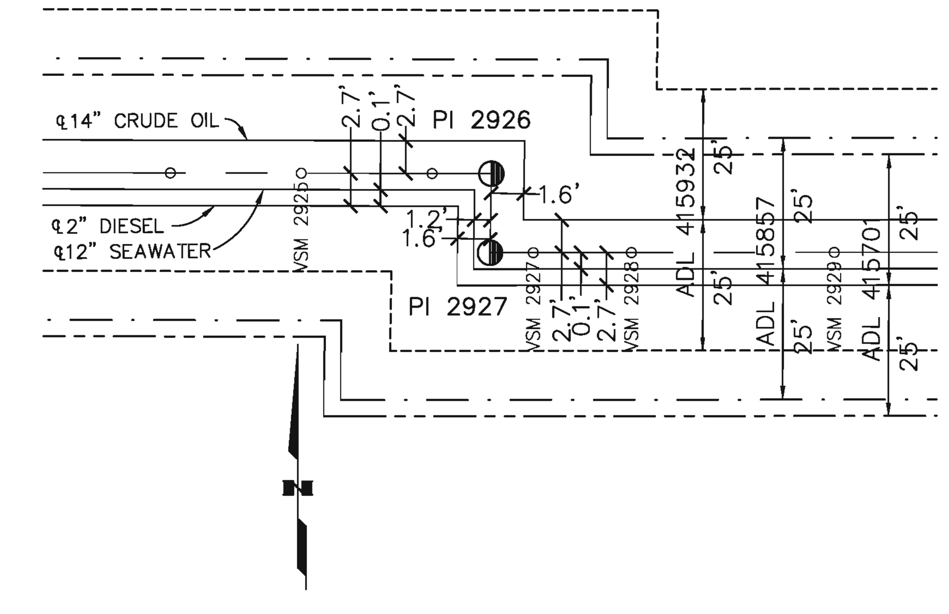

DETAIL – CPF-2 TIE-IN

N.T.S.



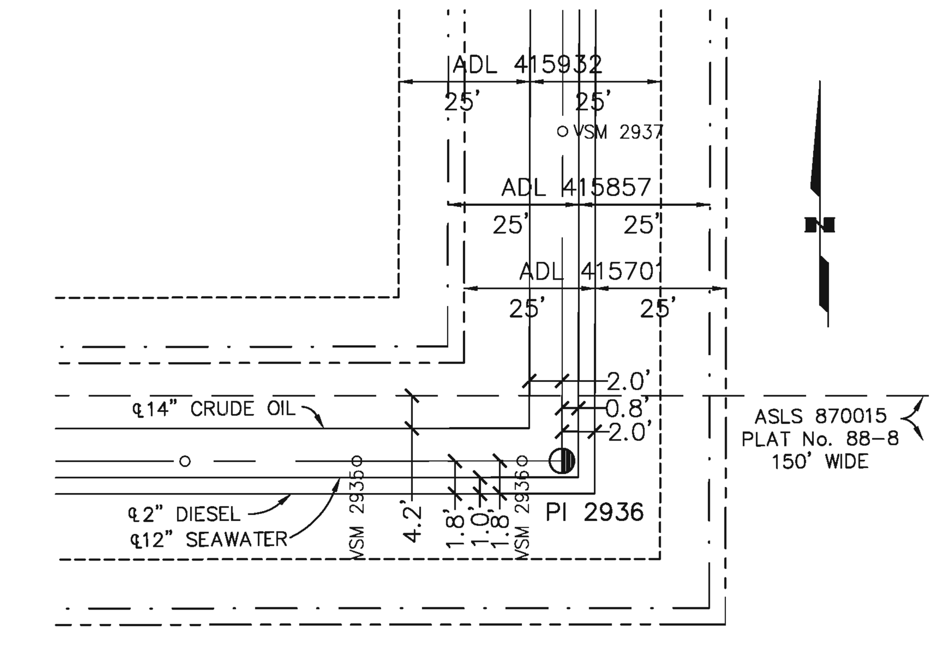

DETAIL – PI 2918

N.T.S.




DETAIL – Z-LOOP PI 2926 & PI 2927

N.T.S.

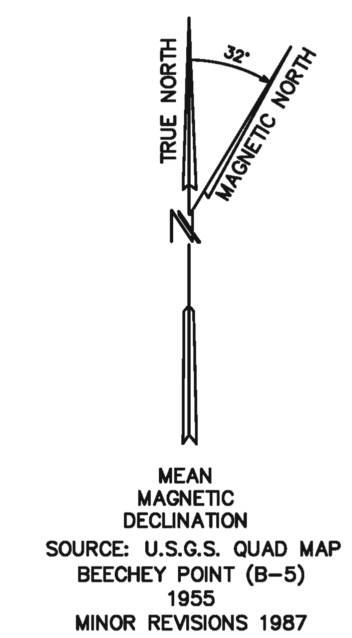



DETAIL – PI 2936

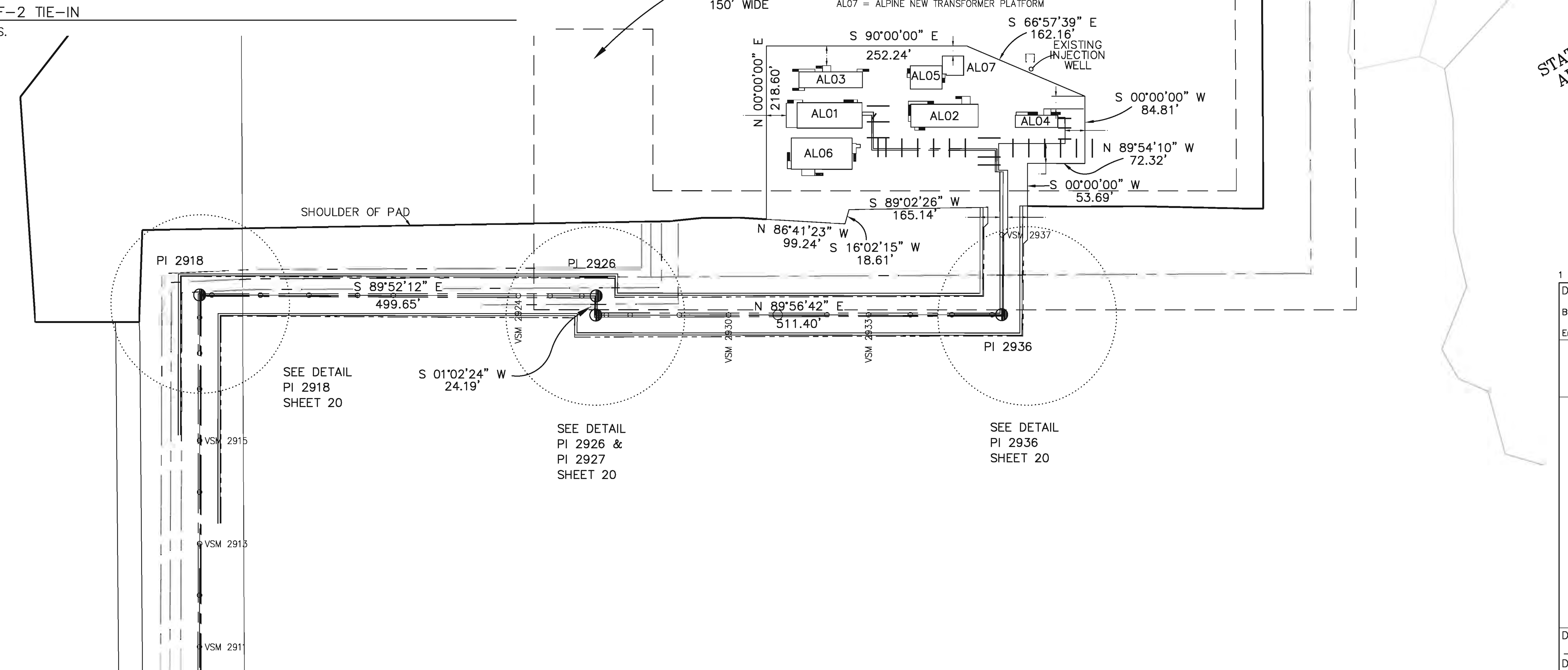
N.T.S.

| PI ID | LATITUDE | LONGITUDE | NORTHING | EASTING | RM #1 | DESC. | RM #2 | DESC. |
|---|---|---|---|---|---|---|---|---|
| 2918 | 70°17'18.551"N | 149°53'15.878"W | 5,955,086.154 | 5,138,68.508 | 22.22' | VSM 2918 | 12.66' | VSM 2919 |
| 2926 | 70°17'18.530"N | 149°53'01.318"W | 5,955,085.021 | 5,143,68.159 | 19.38' | VSM 2926 | 25.37' | VSM 2927 |
| 2927 | 70°17'18.293"N | 149°53'01.332"W | 5,955,060.836 | 5,143,67.720 | 31.31' | VSM 2926 | 10.82' | VSM 2927 |
| 2636 | 70°17'18.288"N | 149°52'46.430"W | 5,955,061.327 | 5,148,79.121 | 13.61' | VSM 2936 | 18.70' | VSM 2B-125 |
| PI C1 | 70°17'18.306"N | 149°52'46.490"W | 5,955,063.179 | 514,877.069 | – | – | – | – |
| PI C2 | 70°17'20.058"N | 149°52'46.486"W | 5,955,241.367 | 514,876.852 | – | – | – | – |
| PI C3 | 70°17'20.059"N | 149°52'46.654"W | 5,955,241.382 | 514,871.078 | – | – | – | – |
| PI C4 | 70°17'20.324"N | 149°52'46.651"W | 5,955,268.383 | 514,871.148 | – | – | – | – |
| PI C5 | 70°17'20.331"N | 149°52'51.189"W | 5,955,268.784 | 514,715.388 | – | – | – | – |
| PI C6 | 70°17'20.762"N | 149°52'51.184"W | 5,955,312.606 | 514,715.500 | – | – | – | – |
| PI C7 | 70°17'20.765"N | 149°52'52.685"W | 5,955,312.738 | 514,663.968 | – | – | – | – |
| PI S1 | 70°17'18.278"N | 149°52'46.407"W | 5,955,060.344 | 514,879.907 | – | – | – | – |
| PI S2 | 70°17'20.058"N | 149°52'46.367"W | 5,955,241.357 | 514,880.920 | – | – | – | – |
| PI S3 | 70°17'20.059"N | 149°52'46.596"W | 5,955,241.377 | 514,873.073 | – | – | – | – |
| PI S4 | 70°17'20.344"N | 149°52'46.592"W | 5,955,270.378 | 514,873.147 | – | – | – | – |
| PI S5 | 70°17'20.351"N | 149°52'51.131"W | 5,955,270.779 | 514,717.388 | – | – | – | – |
| PI S6 | 70°17'20.803"N | 149°52'51.125"W | 5,955,316.768 | 514,717.506 | – | – | – | – |
| PI S7 | 70°17'20.806"N | 149°52'52.829"W | 5,955,316.918 | 514,659.021 | – | – | – | – |
| PI D1 | 70°17'18.269"N | 149°52'46.371"W | 5,955,059.483 | 514,881.174 | – | – | – | – |
| PI D2 | 70°17'19.269"N | 149°52'46.348"W | 5,955,161.097 | 514,881.730 | – | – | – | – |
| PI D3 | 70°17'19.317"N | 149°52'46.205"W | 5,955,166.006 | 514,886.633 | – | – | – | – |
| PI D4 | 70°17'20.078"N | 149°52'46.197"W | 5,955,243.358 | 514,886.779 | – | – | – | – |
| PI D5 | 70°17'20.078"N | 149°52'46.530"W | 5,955,243.387 | 514,875.346 | – | – | – | – |
| PI D6 | 70°17'20.363"N | 149°52'46.526"W | 5,955,272.372 | 514,875.402 | – | – | – | – |
| PI D7 | 70°17'20.360"N | 149°52'44.078"W | 5,955,272.157 | 514,959.414 | – | – | – | – |
| PI D8 | 70°17'20.749"N | 149°52'44.073"W | 5,955,311.688 | 514,959.515 | – | – | – | – |
| PI D9 | 70°17'20.750"N | 149°52'45.323"W | 5,955,311.758 | 514,916.620 | – | – | – | – |
| PI D10 | 70°17'20.692"N | 149°52'45.324"W | 5,955,305.852 | 514,916.612 | – | – | – | – |

CPF2




AL01 = ALPINE LAUNCHER/RECIEVER MODULE
AL02 = ALPINE SEAWATER TRANSFER MODULE
AL03 = ALPINE DIVERT CRUDE MODULE
AL04 = ALPINE AHF TRANSFER MODULE
AL05 = ALPINE SWITCHGEAR/TRANSFORMER MODULE
AL06 = ALPINE NEW SEAWATER TRANSFER MODULE
AL07 = ALPINE NEW TRANSFORMER PLATFORM





## LEGEND

- SET 3 1/4" ALUMINUM CAP ON 5/8"x30" REBAR
- 50' WIDE ADL 415701 14"ø CRUDE OIL LINE
- 50' WIDE ADL 415857 12"ø SEAWATER LINE
- 50' WIDE ADL 415932 2"ø DIESEL LINE
- VSM 0122 — VSM
- VSM 0101A — VSM ANCHOR
- PI-C1 — 14" CRUDE OIL PI NUMBER
- PI-S1 — 12" SEAWATER PI NUMBER
- PI-D1 — 2" DIESEL PI NUMBER

1 METER= 3.2808333 U.S. SURVEY FEET, 1 US ACRE= 0.4047 HECTARES

| DATE OF SURVEY | NAME OF SURVEYOR |
|---|---|
| Beginning 3/01/01<br>Ending 4/12/01 | LCMF Incorporated<br>139 E. 51St.<br>Anch., Alaska 99503 |

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINING, LAND AND WATER
ANCHORAGE, ALASKA

# RECORD OF SURVEY

OF THE ALPINE TO KUPARUK CPF-2 OVERLAND PIPELINE

LOCATED WITHIN
SECTION 32, T. 12 N., R. 5 E.;
SECTIONS 5, 6, 7, 18, 19, 29, 30, 32 AND 33, T. 11 N., R. 5 E.; SECTIONS 12 AND 13, T. 11 N., R. 4 E.; SECTIONS 2, 3, 4, 11 AND 12, T. 10 N., R. 5 E.; SECTION 7, 8, 9, 10, 11, 12, 17 AND 18, T. 10 N., R. 6 E.; SECTIONS 1, 2, 7, 8, 9, 10 AND 11, T. 10 N., R. 7 E.; SECTIONS 5 AND 6, T. 10 N., R. 8 E.; SECTIONS 25, 32, 33, 34, 35 AND 36, T. 11 N., R. 8 E.; AND SECTIONS 20, 21, 28, 29 AND 30, T. 11 N., R. 9 E., UMIAT MERIDIAN, ALASKA

CONTAINING 446 ACRES, MORE OR LESS
BARROW RECORDING DISTRICT, ALASKA

| DRAWN BY CEZ<br>DATE 5/14/03 | APPROVAL RECOMMENDED<br>Statewide Platting Supervisor — Date | | |
|---|---|---|---|
| SCALE 1"=100' | CHECKED APH | SHEET 21 of 21 | FILE NO. LOCATED WITHIN EPF20020040A |

# ATTACHMENT 4

a. 2017 Appraisals (NOT INCLUDED-Due September 2018) CPC will provide the appraisals to the SPCS once the appraisals become available.
b. 2017 Annual Comprehensive Report on Pipeline Activities

# ATTACHMENT 4

a. 2017 Appraisals (*NOT INCLUDED-Due September 2018*)
   CPC will provide the appraisals to the SPCS once the appraisals become available.
b. **2017 Annual Comprehensive Report on Pipeline Activities**

ConocoPhillips
P.O. Box 100360
Anchorage, Alaska 99510-0360
Phone 907.263.4586

**Barry Romberg**
Manager, Alaska Transportation

February 27, 2018

Mr. Jason Walsh
State Pipeline Coordinator
State Pipeline Coordinator's Section
Division of Oil and Gas
3651 Penland Parkway
Anchorage, Alaska 99508

**Re: 2017 Annual Comprehensive Report on Pipeline Activities**

| | |
|---|---|
| Alpine Oil Pipeline | ADL 415701 |
| Alpine Utility Pipeline | ADL 415857 |
| Alpine Diesel Pipeline | ADL 415932 |

Dear Mr. Walsh:

In accordance with Stipulation 1.14.1 of ADL's 415701, 415857, and 415932, ConocoPhillips Company is submitting the enclosed *2017 Annual Comprehensive Report on Pipeline Activities* for the Alpine Pipelines. This year's submittal consists of one *Portable Document Format* (pdf) electronically transferred to you using ConocoPhillips Alaska secure file transfer protocol system in an effort to reduce the amount of paper consumption and save energy.

Please refer any questions, comments, or report improvements to Sandra Pierce at 907-265-6316.

Sincerely,

Barry Romberg
Manager, Alaska Transportation

Enclosure

cc: Electronic Copy

DOT Compliance Specialist, CPAI
CPF3 OPS & DOT Ops Superintendent, CPAI
Manager, WNS Operations, CPAI
Alpine Environmental Coordinator, CPAI

Lanston Chinn , Kuukpik
Brian Boyd, Kuukpik
Teresa Imm, ASRC

Tom Jantunen, CPC
Sandra Pierce, CPC
Emily Zanto, CPC

| | |
|---|---|
| **From:** | Lescanec, Heather A M (DNR) |
| **To:** | Pierce, Sandra M; Romberg, Barry |
| **Cc:** | Walsh, Jason A (DNR); Grundman, Christopher C (DNR); Spco Records |
| **Subject:** | [EXTERNAL]ConocoPhillips Annual Reports |
| **Date:** | Wednesday, February 28, 2018 9:46:56 AM |

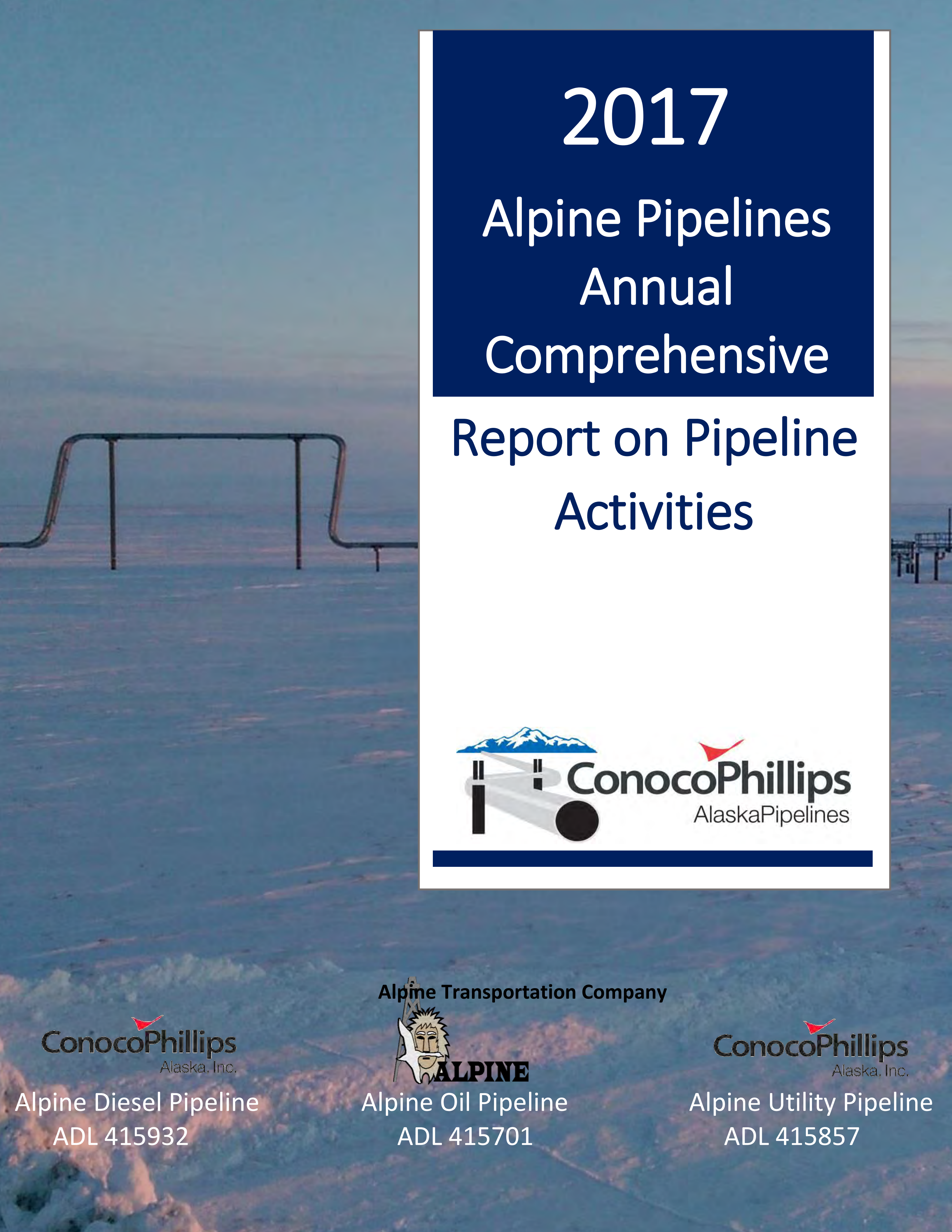
Good morning,

On February 27, 2018, the State Pipeline Coordinator's Section received the 2017 Annual Comprehensive Report for the Alpine Pipelines (ADLs 415932, 415701, 415857), Kuparuk and Kuparuk Extension Pipelines (ADLs 402294, 409027), and the Oliktok Pipeline (ADL 411731). The annual reports play a vital role in our oversight efforts, and we appreciate your timely submittal. Our compliance, engineering, and right-of-way staff members will now begin a review of the document and, if necessary, will follow up to request clarification or additional information.

Please let me know if you have any questions.

**Heather Lescanec**

Lease Compliance Specialist
State Pipeline Coordinator's Section
907.269.6437



# 2017

# Alpine Pipelines Annual Comprehensive Report on Pipeline Activities

ConocoPhillips
AlaskaPipelines

Alpine Transportation Company

ConocoPhillips
Alaska, Inc.

ALPINE

ConocoPhillips
Alaska, Inc.

Alpine Diesel Pipeline
ADL 415932

Alpine Oil Pipeline
ADL 415701

Alpine Utility Pipeline
ADL 415857

# INDEX

*ALPINE OIL PIPELINE ADL 415701*
*ALPINE UTILITY PIPELINE ADL 415857*
*ALPINE DIESEL PIPELINE ADL 415932*

ConocoPhillips

# INDEX

# INDEX

# A. PURPOSE

*ALPINE OIL PIPELINE* *ADL 415701*
*ALPINE UTILITY PIPELINE* *ADL 415857*
*ALPINE DIESEL PIPELINE* *ADL 415932*

ConocoPhillips

# PURPOSE

The *2017 Annual Comprehensive Report on Pipeline Activities* satisfies reporting requirements contained in the Alpine Pipelines Right-of-Way (ROW) Leases [1]Exhibit A and Stipulation 1.14.1. To clarify annual reporting requirements, the Division of Oil and Gas, State Pipeline Coordinator's Section (SPCS), issued letters: 04-017-WW and 10-277-AS. See Table A-1 for reporting requirements.

Table A-1: Annual Report Requirements.

| Lease/Grant | Letter 04-017-WW | Letter 10-277-AS | Requirement |
|---|---|---|---|
| ☒ | ☐ | ☒ | On or before March 1 of every year this lease is in effect the Lessee must submit an annual comprehensive report to the Commissioner on the state of the Pipeline System and its Pipeline Activities. The report shall address, at a minimum: |
| ☒ | ☒ | ☐ | 1) The results of the Lessee's surveillance and monitoring program during the preceding year, including annual and cumulative changes in facilities and operations, the effects of the changes, and proposed actions to be taken as a result of the noted changes. |
| ☐ | ☒ | ☐ | ▪ Provide a summary of the scope of all surveillances, audits, self-assessments, or other internal evaluations performed by the Lessee. |
| ☐ | ☒ | ☐ | ▪ Summarize findings, action items and other observations identified as a result of all surveillances, audits, self-assessments, or other internal evaluations performed by the Lessee. |
| ☐ | ☒ | ☐ | ▪ Describe corrective and protective actions planned or implemented as a result of all surveillances, audits, self-assessments, or other internal evaluations performed by the Lessee. |
| ☐ | ☒ | ☐ | ▪ To the extent known, list by quarter, those surveillances, audits, self-assessments, or other internal evaluations planned for next year. |
| ☒ | ☒ | ☐ | 2) The state of, changes to, and results in the last year from the Lessee's risk management program, Quality Assurance Program, and internal and external safety programs. |
| ☒ | ☒ | ☐ | 3) Lessee's performance under the lease stipulations. |
| ☒ | ☒ | ☐ | 4) Other information on construction, operations, maintenance, and termination activities necessary to provide a complete and accurate representation of the state of the Pipeline System and Lessee's Pipeline Activities. |
| ☐ | ☒ | ☐ | 5) A summary of all events, incidents and issues which had the potential to or actually did adversely impact pipeline system integrity, the environment, worker or public safety, and a summary of the Lessee's response. |
| ☐ | ☒ | ☐ | 6) A summary of all oil and hazardous substance discharges including date, substance, quantity, location, cause, and cleanup actions undertaken. Minor discharges below agreed upon thresholds may be grouped into monthly total amounts, provided the number of separate incidents is reported. |
| ☐ | ☒ | ☐ | 7) Any additional information requested by the State Pipeline Coordinator. |

[1] Alpine Diesel Pipeline Lease ADL 415932; Alpine Oil Pipeline Lease ADL 415701; Alpine Utility Pipeline Grant ADL 415857

# B. OVERVIEW

| | |
|---|---|
| *ALPINE OIL PIPELINE* | *ADL 415701* |
| *ALPINE UTILITY PIPELINE* | *ADL 415857* |
| *ALPINE DIESEL PIPELINE* | *ADL 415932* |

ConocoPhillips

# OVERVIEW

ConocoPhillips Company (CPC) holds two Right-of-Way (ROW) Leases and one Grant with the State of Alaska for the following pipelines:

| Pipeline | Lease / Grant | Alaska Division of Lands Number |
|---|---|---|
| Alpine Oil Pipeline (AOP) | Lease | ADL 415701 |
| Alpine Utility Pipeline (AUP) | Grant | ADL 415857 |
| Alpine Diesel Pipeline (ADP) | Lease | ADL 415932 |

This section presents an overview of each pipeline, summarizes pipeline-specific location and configuration, identifies pipeline ownership, and describes the Lessee's general responsibilities under the lease and grant agreements.

## LOCATION AND CONFIGURATION

Located on Alaska's North Slope in the Colville River Delta and crossing State and Kuukpik owned land[1], the approximately 34.6-mile Alpine pipelines transport products between the Alpine Central Processing Facility 1 (ACPF1) located in the Colville River Unit (CRU) and the Central Processing Facility 2 (CPF2) located in the Kuparuk River Unit (KRU).

### ABOVEGROUND CONFIGURATION

Similar to other North Slope pipelines, the Alpine pipelines route through terrain underlain by permafrost. To prevent the adverse effects of thaw-settlement and to allow wildlife passage, the majority of the pipelines are supported by an above ground system composed of vertical and horizontal members that support each pipeline a minimum of five feet above the tundra. The AOP and AUP are uncoated, insulated with polyurethane to conserve heat, and wrapped in a galvanized steel jacket to protect the insulation. The ADP is uncoated and uninsulated. The exceptions to the above ground configuration are at Kuparuk River Unit (KRU) road crossings and at the Colville River crossing, where the pipelines are located below grade and within air annulus casings.

### COLVILLE RIVER CROSSING CONFIGURATION

At the Colville River crossing, all three of the Alpine pipelines are fusion-bonded epoxy (FBE) coated and located under the river within horizontal directional drilled (HDD) air annulus casings. The AOP and AUP are installed within individual casings. The ADP, two fiber-optic cables (one active and one spare), and a 2-inch conduit for a future power cable, are bundled within a third casing. All three casings are cathodically protected.

1 Kuukpik Owned Land: Vertical Support Member (VSM) 243 to VSM 326; VSM 335 to Colville West Bank, Colville East Bank to VSM 1212.

Table B-1. Pipeline Specific Configuration

| Pipeline or Facility | Fluid Transported | Diameter (inches) | Grade | Cross Country | | | Colville River Crossing | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Wall (inches) | Coating | Insulation (inches) | Wall (inches) | Coating | Insulation (inches) | Casing Diameter (inches) |
| Alpine Oil | Crude Oil | 14 | API 5L-X65 | 0.312 | -- | 3 | 0.438 | FBE | -- | 20 |
| Alpine Utility | Treated Seawater | 12.75 | API 5L-X65 | 0.330 | -- | 3 | 0.330 | FBE | -- | 18 |
| Alpine Diesel | Products [1] | 2.375 | API 5L-X52 [2] | 0.156 | -- | -- | 0.156 | FBE | -- | 8 |

| Pipeline or Facility | DOT Regulated | Piggable | CPM Leak Detection | MOP (psig) | | Temperature (°F) | Flow Rates | Length (miles) | Line Start | Line End |
|---|---|---|---|---|---|---|---|---|---|---|
| Alpine Oil | Y | Maint/ Smart | Y | 2064 | @ | 180 | 145,000 bpd | ~34.6 | ACPF | CPF2 |
| Alpine Utility | N | Maint/ Smart | Y | 1500 [3] | @ | 150 | 135,000 bpd [5] | ~34.6 | CPF2 | ACPF |
| Alpine Diesel | Y | Maint | Y | 1366 [4] | @ | 100 | 15 gpm [5] | ~34.6 | CPF2 | ACPF |

Notes:

[1] As defined in Alaska Statute 38.35.230 (8)

[2] Coil tubing that meets API 5L-X52 criteria

[3] Maximum operating pressure (MOP) limited to 1500 psig

[4] Operated as a low-stress hazardous liquids pipeline (below 20 percent of specified minimum yield strength (SMYS)).

[5] Process Design Flow Rate: Mechanical Analysis of Aboveground Pipeline & Aboveground River Crossings 23100-MBJ-RPT-001, Revision 7, November 2003

### CPF2 Divert Tank "A"

Associated facilities include Divert Tank "A" located on the east side of the KRU CPF2 pad. Designated by the Department of Transportation as a breakout tank, it receives diverted oil from either Alpine or CPF2 allowing the Kuparuk Pipeline Extension or AOP oil flow to continue during periods of pipeline outage.

## OWNERSHIP

The AOP is owned by the Alpine Transportation Company; a general partnership between the Alpine Pipeline Company (APC), Anadarko Alaska Pipeline Systems, Inc., Arctic Slope Regional Corporation Pipeline Company Inc., and the Kuukpik Transportation Company Inc. ConocoPhillips Company (CPC) owns the APC. The CRU working interest owners own both the AUP and ADP.

## RESPONSIBILITIES

Effective 31 December 2002, CPC is the ROW Lease and Grant holder for the three Alpine pipelines, and is responsible for compliance with ROW lease agreement requirements.

On 10 December 2012, CPC designated Barry Romberg as the *Authorized Representative* to perform business related to the Alpine pipeline ROW Leases and Grant. Mr. Romberg oversees the operations and management of the assets; he provides independent oversight and assurance that all pipeline related requirements are satisfactory to CPC management, pipeline owners and the SPCS.

ConocoPhillips, Alaska Inc. (Operator) is the primary CPC Contractor responsible for operating the asset and ensuring the development, implementation, and documentation of required programs, policies, and procedures.

# C. ASSURANCE

*ALPINE OIL PIPELINE* *ADL 415701*
*ALPINE UTILITY PIPELINE* *ADL 415857*
*ALPINE DIESEL PIPELINE* *ADL 415932*

ConocoPhillips

# PROGRAMS

## ALPINE PIPELINES QUALITY PROGRAM

☐ New / Revised

The ConocoPhillips Company is committed to conducting business in a manner that protects the safety and health of employees, its contractors, its customers, the public, and others involved in the operation of its facilities. Furthermore, it is committed to conducting business in a manner that assures public confidence and is compatible with the balanced environmental and economic needs of the communities in which it operates. These commitments require facilities to be designed, constructed, operated, and maintained to accepted standards, and in compliance with all applicable laws and regulations.

Approved by the SPCS on October 3, 2006, the *Alpine Pipelines Quality Program,* Revision 2, defines the elements of a quality system necessary to satisfy these commitments, identifies *what* the system intends to accomplish, and provides guidance for the development of contractor quality plans that define *how* expectations are fulfilled. The Quality Program is reviewed every five years, and the next review is scheduled for 2018.

## QUALITY MANAGEMENT SYSTEMS

### HEALTH, SAFETY, AND ENVIRONMENTAL MANAGEMENT SYSTEM STANDARD

☐ New / Revised


Figure C-1: HSEMS Continuous Improvement cycle

To ensure compliance with the SPCS approved *Alpine Pipelines Quality Program*, the Operator implements the *Health, Safety, and Environmental Management System Standard (HSEMS) issue No. 3.1.* The *HSEMS* identifies the processes required to assess and manage operational risks to the business, its stakeholders, and the environment. The *HSEMS* includes fifteen interrelated elements essential for successful system implementation, including Procedures, Asset and Operating Integrity, Training, Emergency Preparedness, Incident Investigation, Document Control, and Audits. Kuparuk Operations has developed systems, processes, and documents to support and effectively implement each element.

Effective October 1, 2014, the *HSEMS* ensures a continuous improvement cycle of Policy and Leadership, Plan, Do, Assess, and Adjust. Each phase of the cycle includes one or more element that are interrelated and essential for driving performance (Figure C-1).

### CAPITAL PROJECTS MANAGEMENT SYSTEM

☒ New / Revised

Alpine pipeline facilities and equipment must be designed, constructed and terminated in accordance with applicable requirements identified in specifications, drawings, codes, standards, criteria, contract documents, and government regulations. To achieve compliance and assure quality, the *Capital Projects Management System Alaska (CPMSAK) 3.0* provides a central quality function to facilitate the successful implementation of large projects in the business unit. The *CPMSAK 3.0* executive sponsors ensure adequate technical resources are committed to the development and implementation of quality plans, the affected groups have sufficient technical support, and management has the required oversight. CPMSAK 3.0 aligns with the governing CPMS Corporate principles and include the Operator's technical standards, procedures, tools and guidelines, and project templates (Figure C-2).

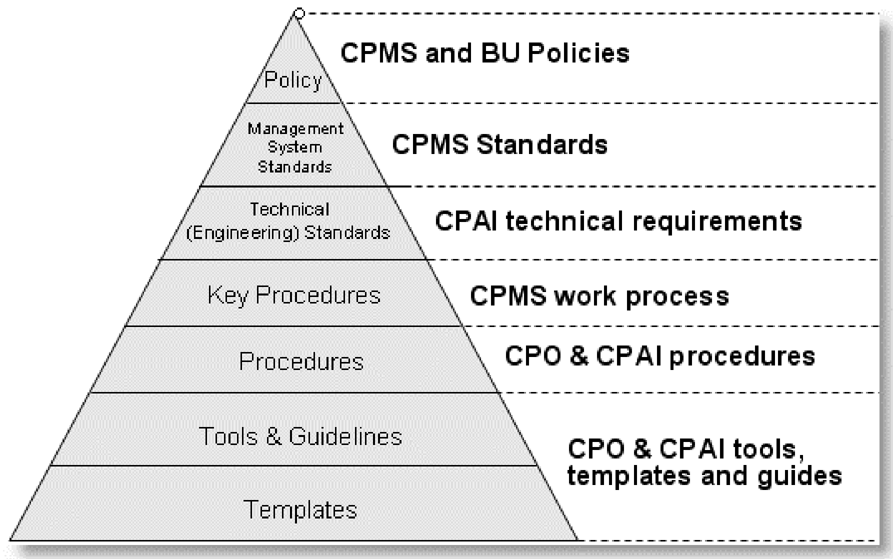



Figure C-2: Depicts how CPMS AK 3.0 aligns with ConocoPhillips corporate CPMS policy and management system standards

Project documentation is maintained through a prescribed Information Management specification. Project closeout includes contractor assessments.

### Operations Compliance Management System

☐ New / Revised

The ConocoPhillips Company utilizes the *Operations Compliance Management System (OCMS)*, Revision 5, dated October 2016, to implement a systematic approach for ensuring pipeline operation in compliance with applicable laws, regulations, and right-of-way lease and grant covenants and stipulations. The OCMS is reviewed every three years and is scheduled for review in 2019.

## Results

This section summarizes year 2017 audits, assessments, and results performed in accordance with the following processes:

- Health, Safety and Environmental Management System Standard
- Capital Projects Management System, Alaska 3.0
- Operations Compliance Management System

Figure C-3 provides a five-year summary of internal and external assessment activities. The pages following include a recap of external agency surveillances, inspections and responses.

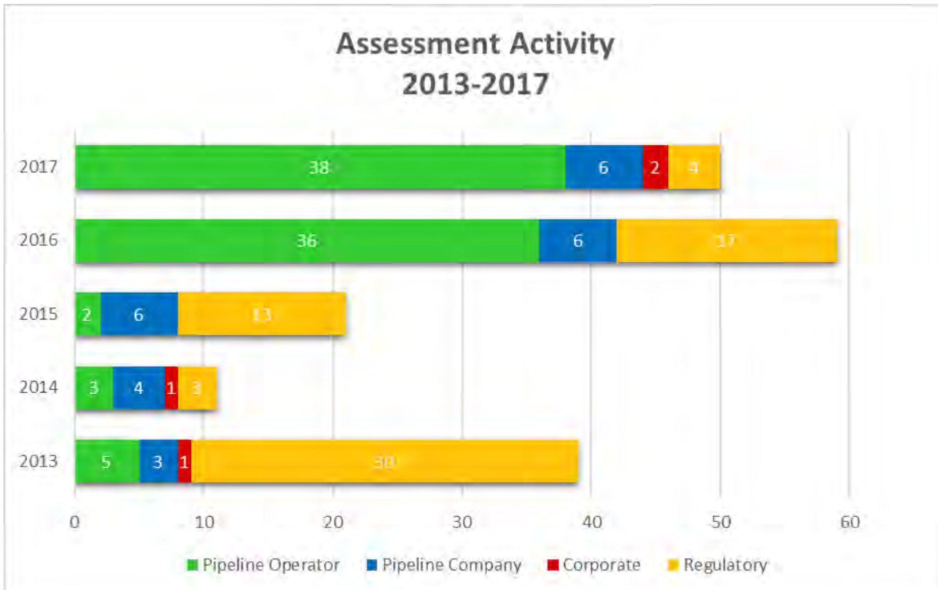



Figure C-3. Assessment Summary for years 2013-2017.

# INTERNAL ASSESSMENTS

## Health, Safety, and Environmental Management System Standard

### Corporate and Business Unit

Corporate and Business Unit HSE compliance audits typically cover Federal and State regulations as well as corporate standards. There was one Corporate HSE compliance audit and one risk analysis survey related to Alpine operations in 2017. Table C-1 provides the number of risk ranked findings and recommendations resulting from each assessment.

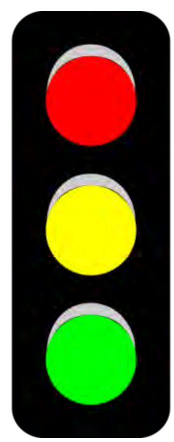


Table C-1: Corporate audits and results of audits.

| **Audit Type** | **Risk Ranked Findings** | | | **Recommendations** |
|---|---|---|---|---|
| | Major | Medium | Minor | |
| *HSE Compliance* | | | 1 | 13 |
| *Risk Analysis Survey* | | 2 | | |

### Contractor

Contractor *HSEMS* audits are a comprehensive review of management system elements. Scoring is based upon written systems and the verification of implementing those systems. Contractors are scored under a *Stoplight Scoring System* of red, yellow, or green.

Contractors scoring red must have a written improvement plan approved by a ConocoPhillips Vice President to work for ConocoPhillips and are closely monitored and re-audited in one year. Contractors scoring yellow develop a corrective action plan to address improvement opportunities within their management systems to increase the overall effectiveness of their programs and/or systems. Contractors scoring green are approved to work without any special provisions.

ConocoPhillips monitors corrective action plans through completion, and reviews them for implementation during the next scheduled audit. In 2017, two Contractor HSE assessments were performed and one non-conformance of significant risk was identified. For more details, refer to Chapter E, Safety.

### Routine Compliance Assessments

ConocoPhillips maintains full-time pipeline compliance personnel who conduct regular assessments of programs that support HSEMS elements. These include but are not limited to the following: annual procedure and program reviews, pre-project design reviews and project close-out documentation, regular audits of routine maintenance documentation and training compliance, and frequent field inspections. These routine assessments are conducted daily and are not included in Figure C-3 audit numbers.

## Quality Management Standard

Operations of the Alpine Pipelines continued in 2017 under the oversight of the Operator, and when necessary, use the Quality Assurance (QA) Department in the Capital Projects Group for certain projects. The guidelines for this oversight program use the criteria established by the *CPMS AK 3.0* and align with quality terms and definitions of ANSI/ISO/ASQ philosophies. All capital projects are periodically reviewed and audited against the CPMS AK requirements to ensure compliance. The QA Supervisor, supported by field surveillance QA personnel, administers this program. There were no QA audits in 2017.

## Operations Compliance Management System

The *OCMS* provides a systematic approach for ensuring pipeline operations and maintenance in accordance with all applicable laws, regulations, and right-of-way covenants and stipulations. Table C-2 provides a list of current year assessments, number of findings or observations, and closure status. Generally, assessments are developed during the 2nd quarter and implemented in quarters 3-4 of the assessment year.

Table C-2. Operations Compliance Management System Assessment Summary

| Number | Description | Final Report | Findings (Fin)/ Observations (Obs) | Open/ Closed |
|---|---|---|---|---|
| **2017** | | | | |
| 2017-1 | Right-of-Way<br>Focus: Lease Performance Compliance Matrix | 12/2017 | 1 Fin | Closed |
| 2017-2 | Operations and Maintenance Procedures<br>Focus: Navigable Waterways and Signage | In Progress | Pending | Open |
| 2017-3 | Operations and Maintenance Procedures<br>Focus: Break-out Tank | In Progress | Pending | Open |
| 2017-4 | DOT/PHMSA Program<br>Focus: DOT Public Awarenss | In Progress | 4 Obs | Open |
| 2017-5 | Right-of-Way<br>Focus: Pipeline Quality Program | In Progress | Pending | Open |
| 2017-6 | DOT/PHMSA Program<br>Focus: Integrity Management Program | 7/2017 | 1 Fin, 20 Obs | Closed |

# EXTERNAL ASSESSMENTS

## STATE PIPELINE COORDINATOR'S SECTION, DIVISION OF OIL AND GAS

In 2017, SPCS staff evaluated compliance with Alpine Pipeline's lease and grant stipulations. Table C-3 provides a recap of SPCS surveillance inspections, and compliance reviews completed; the number of reports documenting observations, and the status of compliance (satisfactory (SAT) or unsatisfactory (UNSAT)).

Table C-3. State Pipeline Coordinator's Surveillance, Document Review and Engineering Inspections.

| Letter | | Surveillance, Document Review, Engineering Inspection | | | | Reports | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Performed | | Pipeline | | | Results |
| Date | Number | Type | Focus Area | From | To | AOL | AUL | ADL | Sat/ Unsat |
| 04/03/17 | 17-144-AS | Surv | HDD and VSMs | 04/03/17 | 04/04/17 | ✓ | ✓ | ✓ | SAT |
| 05/17/17 | 17-166-AS | Surv | DPS Inspection | 05/17/17 | 05/17/17 | ✓ | ✓ | ✓ | SAT[1] |
| 08/04/17 | n/a[2] | Surv | CPF2 Follow-up | 07/30/17 | 07/30/17 | ✓ | ✓ | ✓ | SAT |
| 09/27/17 | 17-311-AS | Surv | CPF2 ROW | 07/10/17 | 07/12/17 | ✓ | ✓ | ✓ | SAT[3] |
| 11/02/17 | n/a | Surv | CPF-2 Follow-up | 08/28/17 | 08/29/17 | ✓ | ✓ | ✓ | SAT[4] |

## OTHER REGULATORY AGENCIES

Alpine Management received Letters of Concern and Warning Letters from PHMSA, dated July 7, 2017 from PHMSA's 2016 Integrated Audits of the Alpine Diesel and Oil Pipelines. The Letters of Concern recommended areas for improving fatigue countermeasures training and procedures and the Warning Letter identified a gap in an annual inspection required under 49 CFR §195.428. Recommendations and concerns were reviewed and appropriately addressed to mitigate any future non-compliance.

[1] Follow-up information requests satisfied, May 25, 2017: Photos of the Kuparuk and Colville River crossings during breakup, Alpine Aerial Surveillance Checklist, Alpine Aerial Surveillance Records.

[2] Two surveillance inspections were considered "opportunistic" by SPCS Compliance Inspectors inspecting other Lessee assets and included an impromptu "drop-in" to inspect Alpine Pipelines assets.

[3] Follow-up action items satisfied August 9, 2017: AHF pipeline contact with SW pipeline insulation added to winter repair list; thermosyphon inspection to continue to ensure increases in scour at two thermosyphons are monitored; AHF secondary supports that are out of alignment included in winter repair work order; ASW corrosion inspection follow-up and best practice sleeve details provided to SPCS Inspectors.

[4] Follow-up action items satisfied, November 27, 2017: Colville River Crossing Reports 2014-2016; Georeferenced VSM data; report/engineering review of thermosyphons at HDD Crossing; VSM and anchor surveillance methodology and frequency of inspection; analysis of ASW corrosion wall loss; thermosyphon repair/replacement action plan; on-pad casing monitoring, quantifiable summary, and 2017 repairs.

# D. RISK MANAGEMENT

*ALPINE OIL PIPELINE* *ADL 415701*
*ALPINE UTILITY PIPELINE* *ADL 415857*
*ALPINE DIESEL PIPELINE* *ADL 415932*

ConocoPhillips

## PROGRAMS

The ConocoPhillips Company and their Operator recognize that comprehensive risk management reduces operating risk and the potential for safety, health, and environmental incidents and liabilities. To ensure effective risk management, the Operator established a variety of systems for identifying potential hazards and liabilities, assessing risk, evaluating prevention and mitigation measures, and ensuring the implementation of control techniques for the continued management of risk associated with activities such as:

- Acquisition and Divestiture
- Design and Construction
- Operations and Maintenance
- Environmental Management
- Waste Management
- Emergency Planning and Response

The Operator proactively implements systems providing a comprehensive approach to manage personal exposures in the work place, and for communicating those exposures to affected employees. The priority of risk mitigation techniques to control a hazard include:

- Engineering controls
- Administrative controls
- Personal protective equipment

## ACQUISITION AND DIVESTITURE

☐ New / Revised

The *ConocoPhillips HSE Due Diligence and Social Issues Due Diligence Standard, Issue No. 3,* effective August 2016*,* outlines requirements to ensure potential liabilities related to health, safety, environmental, and other social issues are sufficiently identified, understood, documented, and addressed prior to all business transactions pertaining to real property or business ventures.

## DESIGN AND CONSTRUCTION

### PROCESS HAZARD ANALYSIS

☐ New / Revised

The *Process Hazard Analysis Standard, Revision 20,* effective September 2016*,* establishes the organizational protocols and technical standards applied to Process Hazard Analysis (PHA) and Process Safety Assessments conducted on new or existing surface facilities. Organizational protocols include workflow and assignment of responsibilities to ensure evaluation of process hazards and adequate control prior to startup of new or modified facilities. Technical standards address how to perform and document a PHA, how to determine risk exposure, and how to determine the adequacy of independent protection levels.

### MANAGEMENT OF CHANGE

☐ New / Revised

The *Management of Change* (MOC) *Process, Revision 1*, effective August 2015, ensures facility design and operational changes do not inadvertently introduce significant new hazards into facility processes. It provides a systematic means to ensure process safety information and operating procedure updates; health, safety, and environmental issue identification and mitigation; and training as necessary, in response to changes.

# OPERATIONS AND MAINTENANCE

## GENERAL

To minimize current and future operations and maintenance risks, the Operator performs or manages, as appropriate to the activity:

- Pre-job safety assessments and planning meetings prior to large maintenance or construction activities
- Post-job reviews to assess job performance and to identify future improvements
- Routine safety meetings to discuss potential areas of concern and identify future improvements
- Maintenance and equipment integrity programs using risk-based evaluation processes
- Insurance surveys to identify and evaluate major exposures for management
- *TAP Root* analyses to evaluate incidents and near misses to reduce repeated incidents

## DEPARTMENT OF TRANSPORTATION PROGRAMS

### Integrity Management Program

☒ New / **Revised**

In accordance with *49 CFR §195.452, Pipeline Integrity Management in High Consequence Areas*, the Operator implements an *Integrity Management Program (IMP)* to enhance and validate pipeline integrity and protect high consequence areas (HCA) that could be affected by an unintended release of hazardous liquids from a pipeline system. The Operator reviews the *IMP* annually and revises sections as necessary. The current program version is Edition 2, Revision 9, issued July 2017. The 2017 review was conducted by the Operator and resulted in minor updates and revisions to program language.

### Operator Qualification Program

☒ New / **Revised**

In accordance with *Subpart G* of *49 CFR 195, Qualification of Pipeline Personnel*, the Operator implements an *Operator Qualification Program* (*OQ Program*) to ensure a qualified workforce to reduce the likelihood and severity of pipeline accidents caused by human error. The program requires the identification of "covered tasks" and the personnel qualified with the knowledge, skills, and ability to perform the covered tasks. Qualified individuals are trained to recognize and respond appropriately to abnormal operating conditions. The Operator reviews the *OQ Program* annually and revises it as necessary. The current program is version 3.8, issued November 2017.

### Public Awareness Program

☐ New / Revised

In accordance with *49 CFR §195.440, Public Education*, the Operator implements a *Public Awareness Program (PAP)* to enhance the continued safe operations of the North Slope pipelines by promoting safe performance and launching communications networks to help the public understand:

- The North Slope pipelines role in the petroleum products transportation system in Alaska and the United States
- How these pipelines function and the product being transported
- Their responsibilities to help prevent pipeline damage

The Operator reviews the *PAP* every four years and revises it as necessary. The current program is Revision 5, issued November 2014.

### Drug and Alcohol (Substance Abuse) Policy

☐ New / Revised

The Operator complies with the *ConocoPhillips Global Substance Abuse Policy*, the *U. S. Substance Abuse Policy*, and the *Drug and Alcohol Policy* for PHMSA-Regulated Employees. In accordance with *49 CFR §199, Drug and Alcohol Testing*, the Operator complies with the *Drug and Alcohol Policy for Pipeline and Hazardous Materials and Safety Administration Regulated Employees*, and implements the corporate *Department of Transportation (DOT) Procedures (Drug and Alcohol)*. These policies and procedures are designed to eliminate substance use and abuse in the workplace and preserve a safe, healthful, and productive work environment for employees.

## ENVIRONMENTAL MANAGEMENT

☐ New / Revised

The *North Slope Environmental Field Handbook*, issued December 2015, provides a general overview of the procedures developed by the Operator, BP Exploration Alaska (BPXA), Caelus, ENI, ExxonMobil Development Company (EMDC), Hilcorp, and Savant Alaska to comply with the environmental regulations applicable to the oil fields. Practices providing the foundation for North Slope environmental management include:

- Planning to identify applicable permit requirements, spill prevention practices, or environmental restrictions
- Ordering supplies and material carefully to avoid hazardous materials and minimize waste
- Developing a waste management plan to identify the disposition of waste generated for a project in advance
- Keeping all vehicles and equipment in good working condition and initiating repairs immediately if needed
- Using portable liners under all fluid transfer points
- Reporting spills immediately per operating unit procedures

## WASTE MANAGEMENT

☐ New / Revised

The *Alaska Waste Disposal and Reuse Guide,* Revision 10, issued jointly by the Operator and BPXA in May 2015, provides consistent waste management guidance for employees and contractors to help ensure compliance with applicable regulations and company policies.

## EMERGENCY PLANNING AND RESPONSE

### Emergency Action Plan

☒ New / **Revised**

The *Alpine Facility/Drillsite Emergency Action Plan (EAP),* valid through November 2018, identifies responses for situations with the probable or actual loss of life, extensive injuries, environmental damage, or significant business interruption during the operation of facilities and pipelines within the Alpine area. The plan is designed to:

- Provide a prompt and efficient response action procedure and organization to ensure the safeguard of personnel, property, and environment
- Minimize business interruption
- Provide prompt notification of all affected parties

*Emergency Action Plan* reviews are completed on an annual basis to ensure all details contained in the procedure are current. Revisions incorporated in 2017 include updates to phone numbers, radio talk groups, notification charts, flow charts and the incident command structure.

### Operations Business Recovery Plan

☐ New / Revised

The *Western North Slope Operations Business Continuity Plan*, updated August 7, 2015, addresses business resumption should an event occur which is beyond the scope of standard operating procedures. This plan offers guidance to:

- Minimize the effect of an event on Operations by providing a set of procedures and tasks to be used, in the event of a disaster
- Restore vital business functions to insure business continuity
- Minimize the number of decisions which must be made during an event
- Reduce WNS Operation’s dependence on the participation of any one specific person or one specific group of people in the recovery of the Operation’s business function
- Minimize the need to develop, test, and correct new procedures during recovery
- Curtail the adverse impact of lost data, recognizing that the loss of some transactions is inevitable
- Compress the elapsed time impacting the recovery process
- Minimize the losses associated with extended business malfunctions
- Reduce confusion, exposure to errors and eliminate duplication of effort

The plan is reviewed every six months to ensure all business processes, resources, and alternate recovery site plans, contact numbers, transportation methods and alternates are validated and assure the plan remains valid and functional.

## OTHER RISK MANAGEMENT PROCESSES

Other proactive risk management processes utilized during design, construction, operations, and maintenance include:

- Process Safety Management (PSM), Employee Participation Plan
- Health, Safety, and Environmental Policies

### Process Safety Management, Employee Participation Plan

☐ New / Revised

The *Operator’s PSM Employee Participation Plan and Roadmap*, provides an overview of mechanisms to optimize employee participation in the evaluation, implementation, and maintenance of PSM activities.

Programs and methods available for employees to identify potential hazards or corrective and mitigating measures include, but are not limited to:

- PSM Committees
- Alaska Safety Handbook Revision Process
- WINGS Safety in Motion Program
- Process Safety Information
- Process Hazard Analysis
- Operating Procedures
- Employee Training
- Contractor Requirements
- Pre-Startup Safety Review
- Mechanical Integrity
- Hot Work Permit
- Management of Change
- Incident Investigation
- Planning and Response
- Compliance Safety Audits

### Health, Safety, and Environmental Policies

☒ New / **Revised**

Numerous HSE policies and standards are used by the Operator to evaluate, measure, and control potential hazards to personnel and contractors. The following were reviewed and if necessary, revised during 2017.

- Risk Register Procedure
- Hearing Conservation Procedure
- In Service Bolting Procedure
- Steam Cleaning and Purging Procedure
- Chemical Inventory Procedure
- Hazard Communication Procedure
- Critical Lift Plan
- Medical Surveillance Guideline

The following procedures are scheduled for review in 2018.

- Portable Multi-gas Equipment Procedure
- Cold Cutting Procedure
- CARSEAL Procedure
- Hydrogen Sulfide Procedure
- SimOps Procedure
- Journey Management Procedure
- Fatigue Management Procedure
- Permit to Work Procedure

# Results

## DESIGN AND CONSTRUCTION

### Process Hazard Analysis

PHA nodes associated with an Alpine Pipeline were revalidated during 2017. Table D-1 provides a summary of the Process Hazard Analysis (PHAs) the Operator completed, and the number of findings resulting from the analysis.

Table D-1. Process Hazard Analysis

| Pipeline AOP | Pipeline AUP | Pipeline ADP | PHA Title | Finding |
|---|---|---|---|---|
| ■ | | | Pipeline - Crude Oil Pig Launcher | 1 |

| Pipeline AOP | AUP | ADP | PHA Title | Finding |
|---|---|---|---|---|
| ■ | | | Alpine to Kuparuk Crude Oil Pipeline | 0 |

### MANAGEMENT OF CHANGE

Management of Change (MOC) actions associated with design and construction were completed during 2017. Table D-2 provides a summary of MOCs the Operator completed, or that are in progress.

Table D-2. Management of Change

| Pipeline AOP | AUP | ADP | MOC Title | Date Completed |
|---|---|---|---|---|
| ■ | | | Hot Tap and Stopple | In Progress |
| ■ | ■ | | SW PL warm up tie in | In Progress |
| | | ■ | ADP Temporary fluid transfer pump change | In Progress |
| ■ | | | APL Leak Detection Modification for BRPC | On Hold |
| ■ | | | Hot Tap APL for Brooks Range | On Hold |

## OPERATIONS AND MAINTENANCE

### GENERAL

In 2017, AOP and ADP each received a Warning Letter (52017015W, 520176030W), and a Letter of Concern, (520175016C, 520176927C), following a 2016 PHMSA/DOT Integrated Inspection of the Alpine Oil and Diesel Pipelines. Concerns in both letters were reviewed, and addressed accordingly.

### DEPARTMENT OF TRANSPORTATION PROGRAMS

#### Annual Reports

In 2017, the *2016 Annual Reports -- Hazardous Liquid Pipeline Systems* were submitted for the DOT-regulated pipelines as required by 49 CFR §195.49, *Annual Report.*

#### Advisory Bulletins

Table D-3 provides a summary of Advisory Bulletins applicable to APL Operations, issued or addressed during this reporting period.

#### Final Rules

Table D-4 provides a summary of Final Rules that PHMSA published in 2017.

### Integrity Management Program

Table D-5 provides a summary of 2017 *IMP* evaluation results and the status of previous year outstanding actions.

### Operator Qualification Program

Table D-6 provides high-level *OQ Program* metrics for the previous and current year including the number of program participants, number of covered tasks, and the status of the required program evaluations.

### Public Awareness Program

The *PAP* requires communications to various stakeholder audiences to ensure awareness of the following:

- The purpose, description, and location of the DOT-regulated North Slope pipelines and facilities
- Potential hazards and prevention measures associated with the pipelines and facilities
- Emergency preparedness activities and the stakeholder's role in the process
- Who should be contacted in the event of an emergency or if additional information is desired

Table D-7 provides a summary of communications, planned methods and frequency, number of communications distributed during the last delivery, and the date of the last formal communication. The Operator has extensive communication networks not represented in this summary.

Table D-8 provides the status of program implementation evaluations administered every four years. These evaluations are intended to determine the effectiveness of outreach, the level of individual knowledge, identify any changes in behavior, and the changes to bottom-line results.

Table D-3. Advisory Bulletins

There were no Advisory Bulletins for Pipelines in Liquid Service issued for 2017.

Table D-4. PHMSA Final Rules

| Effective Date | Summary | Action |
|---|---|---|
| 3/24/17 | **Expanding the Use of Excess Flow Valves in Gas Distribution Systems to Applications Other Than Single-Family Residences**<br>PHMSA is amending the pipeline safety regulations to address requirements of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Act), and to update and clarify certain regulatory requirements. Among other provisions, PHMSA is adding a specific time frame for telephonic or electronic notifications of accidents and incidents and adding provisions for cost recovery for design reviews of certain new projects, for the renewal of expiring special permits, and setting out the process for requesting protection of confidential commercial information. PHMSA is also amending the drug and alcohol testing requirements, and incorporating consensus standards by reference for in-line inspection (ILI) and Stress Corrosion Cracking Direct Assessment (SCCDA). | Final Rule Distributed 1/23/2017<br>CPAI has incorporated changes in notifications, Control Room Staff Team Training, and reviewed and updated affected documents. |

Table D-5. Integrity Management Program Evaluation Summary

| Category | Action / Opportunity | Status / Comments | Completion |
|---|---|---|---|
| High Consequence Area (HCA) Identification | By 30 June of each year, review the accuracy of the HCA, pipeline, and facility data to determine whether segment boundaries or other analyses and assumptions require revision due to the introduction of new or revised information. | Completed review/revision process | 03/01/17 |
| | Annually, and one year from the last submission, provide National Pipeline Mapping System (NPMS) confirmation the pipeline and contact information in the system is accurate or revise information for incorporation into the system. | Completed pipeline and contact information | 03/15/17 |
| | As a result of reviews, enhance HCA Pipeline Segment Maps and databases. | Completed during HCA evaluation | 03/01/17 |
| Risk Assessment | Perform annual risk assessment screening evaluation by 31 March. | Completed screening evaluation. Personnel change delayed assessment evaluation | 05/22/17 |
| | If required as a result of the risk assessment screen evaluation, perform risk assessment. | Completed risk assessment for APL. | TBD |
| Preventive and Mitigative Measures (P&MM) | Perform annual screening evaluation by 31 March as part of risk assessment screening evaluation. | Completed screening evaluation | 03/31/17 |
| | Review and further identify P&MM action items during annual Data Integration meeting. | Conducted data integration meeting | In Progress, due for completion 01/31/18 |
| | Perform P&MM Evaluation within 18 months of an integrity inspection to include ILI results. | Completed P&MM evaluation on APL. | TBD |
| Data Integration | Annually by 31 January of the following year, integrate all monitoring, mitigation and inspection data for a clear picture of all damage and risks to the integrity of the North Slope DOT-regulated lines. | Conducted data integration meeting | In Progress, due for completion 01/31/18 |

Table D-6. Operator Qualification Program Statistics

**ALPINE PIPELINES**

| PARTICIPANTS (Program Wide) | 2016 CPAI | 2016 Contractor | 2016 Total | 2016 Change | 2017 CPAI | 2017 Contractor | 2017 Total | 2017 Change |
|---|---|---|---|---|---|---|---|---|
| | 339 | 579 | 918 | 189 | 263 | 487 | 750 | (168) |

**COVERED TASKS**

| Category | 2016 Total | 2016 Change | 2016 Comments | 2017 Total | 2017 Change | 2017 Comments |
|---|---|---|---|---|---|---|
| Breakout Tanks / Pump Stations | 0 | 0 | | 0 | 0 | |
| Corrosion Control | 6 | 1 | Tape Wrap Coating Application added | 6 | 0 | |
| Pipeline Operations | 2 | 0 | | 2 | 0 | |
| Pipeline Repairs | 13 | 1 | Install a Lokring Fitting added | 11 | -2 | Thermit Welding and Inspection |
| Right-of-Way | 5 | 0 | | 5 | 0 | |
| Valves | 2 | 0 | | 2 | 0 | |
| Miscellaneous | 9 | 0 | | 9 | 0 | |
| Total | 37 | 2 | | 35 | -2 | |

**EVALUATIONS**

| Activity | Freq | 2016 Task / Comment | 2017 Task / Comment |
|---|---|---|---|
| Performance Monitoring<br>Goal: 2 different tasks annually | 1 Y | 3rd party audit completed in 2016. Recommendations were reviewed and changes implemented as appropriate. | 3035 Breakout Tank<br>4901 Bolting<br>4514 Inspect Pipeline, Mechanical |
| Record Database Review | 1 Y | 3rd party audit completed in 2016. | Completed |
| User Feedback Survey<br>Goal: 10 Users | 3 Y | Completed in 2016, working on improvements based on feedback | Completed in 2016, next due 2019 |
| Program Review | 1 Y | Version 3.7 release 30 November 2016 | Version 3.8 release 30 November 2017 |

Table D-7. Public Awareness Program Communications Summary

| Stakeholder Audience | Method | Frequency | Total | Last Delivery |
|---|---|---|---|---|
| Affected Public, Hunters, and Recreational Vehicle Users | Brochure [1] | 3 Yrs | 200 | 11/15/15 |
| Affected Public: Nuiqsut Outreach Program [2] | Various | Various | 80 | 11/03/16 |
| Public Officials | Letter | 3 Yrs | 7 | 11/14/16 |
| Emergency Officials | Letter | 1 Yr | 7 | 11/07/17 |
| Other: Pipeline Operators | Cultural Awareness | 1 Yr | 659[3] | On-going |
| Other: Third-Party Contractors | Brochure [1] | 1 Yr | 350 | On-going |
| | Non-Objection | Conditional | 9 | -- |
| Other: Land Developers / Exploration Contractors | Conditional | Conditional | -- | -- |

[1] The Operator provides a Pipeline Awareness brochure at Security Checkpoints when the Alpine to CPF2 ice road is available. By doing so, a variety of stakeholders received the communication. This brochure was also distributed via email to all Kuparuk and Alpine contractors for pipeline safety awareness.

[2] The Operators Community Representative visits with the Village of Nuiqsut year-round and there is an office in the Nuiqsut City office used by staff and for meetings with community groups. Interaction with the village increases during the winter months when the Alpine to CPF-2 ice road is available. Frequent verbal announcements are made over the local CB channel and information postings are placed in key locations in town. Groups the Operator frequently interacts with include: Kuukpik Corporation, Nuiqsut City Council, Kuukpikmiut Subsistence Oversight Panel, Native Village of Nuiqsut, Trapper School, and the Nuiqsut Volunteer Fire Department. In addition, the Operator annually publishes a newsletter highlighting the Operator's activities near Nuiqsut and slope wide. The newsletter is inserted into the local newspaper and is sent to all box holders in Nuiqsut.

[3] Cultural Awareness Training is provided to Operator personnel and contractors, as well as, the personnel and contractors of other pipeline operators.

Table D-8. Public Awareness Program Effectiveness Evaluation Status, administered every four years. The next evaluation period is 2020.

| Stakeholder Audience | Method | Issued | Received |
|---|---|---|---|
| Affected Public, Hunters, and Recreational Vehicle Users | ▪ Mailed Pipeline Safety Survey English and Inupiat<br>▪ Facebook Pipeline Safety Survey English | 125 | 80 |

# E. SAFETY

*ALPINE OIL PIPELINE* *ADL 415701*
*ALPINE UTILITY PIPELINE* *ADL 415857*
*ALPINE DIESEL PIPELINE* *ADL 415932*

ConocoPhillips

# PROGRAM

## ALASKA SAFETY HANDBOOK

☒ New / Revised

Revised in 2018, the *Alaska Safety Handbook (ASH),* developed by the Operator and other North Slope Operators, establishes a standardized set of safety procedures for uniform application. This handbook defines standards of conduct and explains individual safety responsibilities. Understanding of, and compliance with, these safety rules are requirements of employment.

## CONTRACTOR PROGRAMS

In addition to the *ASH,* contractors implement their own plans and programs, which include health, safety, and environmental (HSE) performance objectives and procedures. Table E-1 lists the Operator's primary contractors, the service they provide, their safety program title, and whether the program was revised since the last Annual Report submission.

Table E-1. Contractor Safety Programs

| Contractor | Service | Program | |
|---|---|---|---|
| Alaska Clean Seas | Spill Response and Cleanup | Health, Safety and Environmental Manual: September 2010 | ☐ New / Revised |
| ASRC Energy Services | Field Maintenance | ASRC Energy Services HEST PP&G Manual, Rev 7: April 2013 | ☐ New / Revised |
| Baker Hughes Corp. | Pigging Data Gathering & Evaluation Services | HSE & Security Management System Overview: August 2011 | ☐ New / Revised |
| $CH_2M$ HILL | Engineering and Construction | Target Zero Management System Manual | ☐ New / Revised |
| Kakivik Asset Management, LLC | Corrosion Monitoring and Inspection | Health, Safety, and Environmental Manual, Rev 1.6: June 2013 | ☐ New / Revised |
| Lounsbury & Associates , Inc. | Annual Surveillance and Monitoring | Lounsbury & Associates, Inc. HSE Program: April 2011 | ☐ New / Revised |
| NMS / Security | Alpine Security | Employee Safety Handbook | ☐ New / Revised |
| Udelhoven Oilfield System Services | General Contracting / Special Needs | Health Safety and Environmental Handbook, Revision 4: March 2011 | ☐ New / Revised |
| UMIAQ, LLC | Field Surveying | Ukpeagvik Inupiat Corporation<br>Health, Safety, and Environmental Handbook: April 2009 | ☐ New / Revised |

# ALASKA OCCUPATIONAL SAFETY AND HEALTH ADMINISTRATION REVIEW

Alpine continues to refine its HSE programs under a continuous improvement philosophy by including workforce involvement in the process, both to ensure employee buy-in and to collect key inputs from those who implement the HSE Incident Free Culture.

## RESULTS

Alaska Occupational Safety and Health Administration (AK OSHA) recertified the Alpine Facilities' status to remain a Voluntary Protection Program (VPP) Star Facility.

In 2017, Alpine conducted an annual VPP assessment. VPP assessments provide input and feedback from the workforce regarding Alpine's commitment to safety. Overall, the workforce response was positive; and all responses were tabulated and reviewed for system improvement. The 2017 VPP assessment will be submitted to AK OSHA the first quarter of 2018 for their review.

# OCCUPATIONAL SAFETY AND HEALTH ADMINISTRATION REPORTABLES

Alpine achieved one of its best years ever for overall employee and contractor safety annual performance in 2017. E-2 provides a recap of safety statistics for years 2013-2017 for Operator and contract personnel working on the Alpine pipelines. Additional information is provided in Section K.

| | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|
| OSHA Reportable | | | | | |
| Lost Time Incidents | 0 | 0 | 0 | 0 | 0 |
| Restricted Work Incidents | 0 | 0 | 0 | 0 | 0 |
| Medical Treatment Incidents | 1 | 0 | 0 | 0 | 0 |

Table E-2. Safety Statistics

### HSE SELF-ASSESSMENT AUDIT

Alpine conducted an HSE Compliance and Management System Corporate Audit in 2017. Using the ConocoPhillips (COPA) Risk Matrix, the audit team determined the risk categories of the non-conformances. Of the 1 non-conformance, none were high risk and 1 was of medium risk. Zero DOT related non-conformances were identified.

### CONTRACTOR HSE AUDIT

Two contractor HSE Assessments were conducted in 2017:

- Little Red Services, Inc. (LRS) was conducted October 24 – November 1, 2017 at field operational areas. Five non-conformances were found of which one of them were of significant risk[1].
- Schlumberger was conducted October 24 – November 1, 2017 at field operational areas. Seven non-conformances were found of which none of them were significant or high risk[1].

Both audits were conducted in accordance with COPA Contractor HSE Management Policy and Audit Verification Procedure, *Contractor HSE Assessment*. An audit team consisting of representatives from COPA HSE Contractor Management, Training, Industrial Hygiene and Beacon Occupational Health and Safety conducted these independent and objective audits. Standard audit practices of management system pre-view, management interviews, field observations, and document and records review formed the foundation of these reports.

## PROACTIVE MEASURES

The use of a "proactive measures" approach, focusing on behavioral observations, near miss reporting, and auditing, as a process to identify and address "at risk" behaviors and areas for improvement continued in 2017. Figure E-1 summarizes 2013 - 2017 results for the Alpine Development.

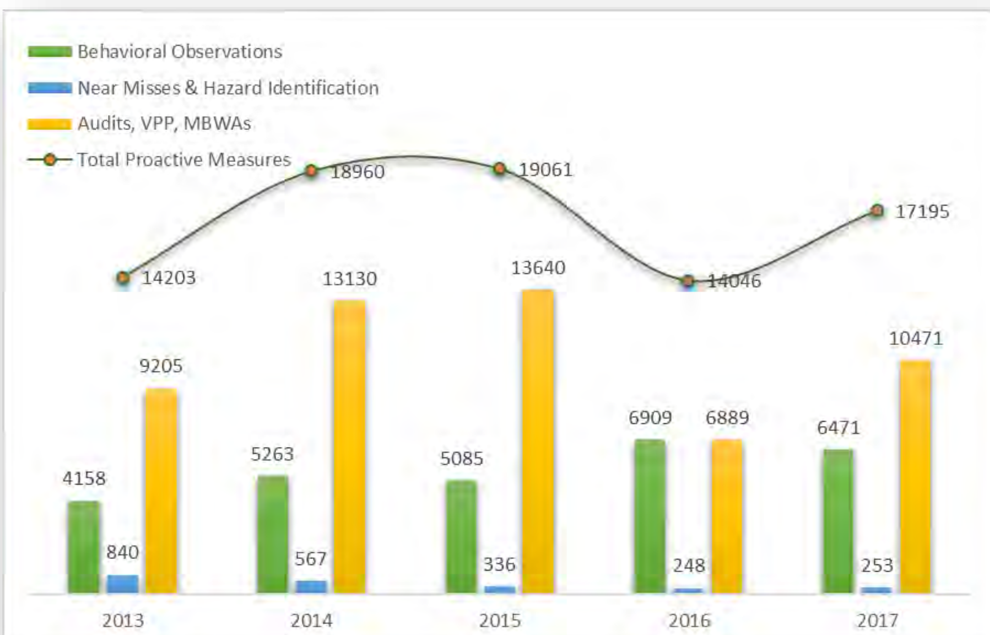



Figure E-1. Proactive Measures

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[1] The audit team utilizwa the COPA Risk Matrix to determine risk categories.

# F. OIL AND HAZARDOUS SUBSTANCE DISCHARGES

*ALPINE OIL PIPELINE ADL 415701*
*ALPINE UTILITY PIPELINE ADL 415857*
*ALPINE DIESEL PIPELINE ADL 415932*

ConocoPhillips

# OIL AND HAZARDOUS SUBSTANCE DISCHARGES

## DISCHARGES

The *Discharge Summary* in Table F-1 provides a record of pipeline system discharges, discharges related to pipeline activities, and third-party discharges which occurred within the ROWs for the reporting year.

Table F-1. Right-of-Way Discharge Summary

| Date | Pipeline | | | Location | Incident / Remediation |
|---|---|---|---|---|---|
| | APL | ADP | AUP | | |
| **PIPELINE RELATED** | | | | | |
| - | - | | - | - | - |
| **NOT PIPELINE RELATED** | | | | | |
| 02/08/17 | | | ■ | CPF2 Chemical Module AL06 | Piping pinhole leak of 2 cups seawater was discovered inside of the module, outside of SPCS Pipeline System. Piping was replaced. |
| 02/20/17 | | | ■ | CPF2 Chemical Module AL06 | Piping pinhole leak of ½ gallon of seawater was discovered inside of the module, outside of SPCS Pipeline System. Piping was replaced. |
| 03/24/17 | | | ■ | CPF2 Chemical Module AL06 | Valve body leak of 2 cups seawater to pad just outside of the module, outside of SPCS Pipeline System. The valve was replaced. |

## PREVENTION AND RESPONSE

## OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

☒ New / Revised

### STATUS

The *Alpine Development Area Oil Discharge Prevention and Contingency Plan (ODPCP)* provides prevention strategies and response plans to limit the spread of a spill, minimizing potential environmental impacts, and to provide for the safety of personnel. This plan relies heavily upon information provided in the *Alaska Clean Seas (ACS) Technical Manua*l and identifies specific tactics, maps, and incident management resources in place to effectively respond to a spill event.

### AGENCY REVIEWS AND APPROVALS

February 2017, the Alaska Department of Environmental Conservation (ADEC) approved the *ODPCP* (CPlan ID #4140) through 2023. A copy of the approval letter and effective C-Plan is available at: http://dec.alaska.gov/Applications/SPAR/PublicMVC/IPP/ApprovedCPlans

## PROOF OF FINANCIAL RESPONSIBILITY

As required by Alaska Statute 46.04.040 and Alaska Administrative Code 18 AAC Chapter 75, Article 2, the Operator received the annual *Certificate for Proof of Financial Responsibility* to respond to spill damages associated with the Alpine Oil Pipeline. The certificate is valid through April 2018. The certificate application is submitted to ADEC annually at the end of February.

# SPILL DRILLS

During 2017, the Alpine Pipeline Operator exercised the Incident Management Team (IMT) and field response teams by means of the following scenarios:

## SUNDOG WELL INCIDENT – EXPLORATION WELL CONTROL SCENARIO (JUNE 22, 2017)

This was an announced exercise. This exercise contained a mobilization of Alpine and Anchorage personnel. At Alpine the IMT, FD, and SRT mobilized. In Anchorage, the Functional Support Teams (FSTs) stood up, specifically the Source Control FST and Public Information Officer (PIO). The scenario was based on WCD scenario, #2 out of the Alpine ODPCP. The scenario used a simulated date and weather data to create appropriate conditions. The scenario involved a loss of well control. This exercise was conducted in accordance with the Alpine EAP. The exercise was initiated at 0600 on June 22nd by the Exercise Controller. The exercise concluded with a debriefing in the Alpine EmOC.

**Drill Scenario:** During the morning hours on February 1, 2018 the well conditions of Putu exploration well are stable, with details as follows:

- BHA information Attachment I
- Mud weight in well 10.0 ppg Spud Mud
- Drilling 12.25” surface open hole @ 2000’MD
- 650 GPM @ 1980 PSI
- Unexpectedly drilled into the shallow gas pocket

At 01:00 on February 1, 2018 Doyon 141 unexpectedly drills into a shallow gas pocket and the well flow was observed at the flowline and accelerate very quickly into a very strong flow. High gas units at the flowline were observed. The rig crew worked to respond accordingly.

01:10 Picked up the top drive until the tool joint cleared the Diverter and the kelly cock is just above the rotary table.
01:15 Shut down the pumps and checked well for flow. Well was flowing
01:20 Driller closed diverter, simultaneously opening diverter valve(s).
01:25 Floorhand #1 ensured that standpipe manifold is lined up for both mud pumps and prepared for rig evacuation. Floorhands #2 and #3 proceeded to an area of the drill site where they could confirm diverter valve opening
01:30 Derrickman lined up both mud pumps on the hole and prepared for rig evacuation.
01:35 Motorman observes accumulator unit has closed and prepares for rig evacuation.
01:35 Drilling and Wells Supervisor notified.
01:40 Driller turns on both mud pumps and initiates evacuation drill.
conjunction with this drill.
01:45 Sounded evacuation rig alarm.
01:50 All potential combustion sources shut-down on rig.
01:50 Forklift driver, roustabout(s), and pit watcher (if available) proceed to safe briefing area, assembled Scott Air Paks and prepare to support rig evacuation.
01:55 All hands reported to the safe briefing area.

Trajectory: The simulated discharged spud mud and gas is ejected through a 75’ X16” inch diverter line at an undetermined rate.

- Eighty percent of the drilling discharged falls within 650 feet of the well.
- The remaining twenty percent of the fluid discharged falls within 650 and 850 feet.

Environmental Conditions: Temperature -20'F, with wind speeds from the northeast at 18 knots. **End Scenario.**

Approximately ninety (90) individuals participated in the exercise including IMT members, FD members, SRT Members, the Source Control Team (Anchorage), the PIO (Anchorage), ADEC (in Anchorage), North Slope Borough (in Alpine), facilitators and members of TRG (in Anchorage and Alpine).

This incident served as the Announced Exercise for the year, satisfied 15 of the 15 NPREP components and served as a WCD scenario as defined in the NPREP guidelines which COP complies with per the Alpine ODPCP and Alpine EAP.

## Alpine Aviation Event (February 23, 2017)

The Alpine IMT experienced a Real Event on February 23, 2017 that satisfied the requirement for an Unannounced Exercise. On the 23rd while attempting takeoff the Conquest aircraft exited the runway veering to the right. Emergency response mobilizations took place at Alpine and Anchorage in support of the incident. The Command Center was located at Alpine which included the IMT, FD, MERT and SRT. In Anchorage, FSTs: Legal, Family Assistance, and the PIO stood up to support the response.

**Real Event:** On February 23rd at 10:10 am the Conquest aircraft while attempting to take off and before leaving the ground, went off the runway veering to the right. The aircraft landed just off the angle of the runway. There were 2 pilots and 5 passengers on the aircraft at the time.

Nearby witnesses called Alpine Security via radio to report the emergency. Passengers and pilots disembarked the aircraft and returned to Alpine camp via nearby witnesses. All passengers were taken to the Alpine medical clinic in work trucks and the camp security transport bus.

At 10:11 am Alpine emergency services were notified of the events and responders were paged out. The Fire and Rescue Team mobilized equipment to assess the scene. The first priority of the assessment was to ensure all parties had exited the aircraft. There was no fire and all energies were secured however a leak was observed. The leak was addressed, and containment placed up under the source. The fuel was leaking at an estimated rate of 1 gal/hr. and being routed to secondary containment (duck pond). A plan was put in place to check on the leak every half hour until 3PM and then to check on the leak every 2 hours thereafter.

At 10:40 am the IMT stood up for the reactive phase of the incident and to develop an initial incident action plan. While the Alpine IMT was ramped up in the EmOC, the SRT, MERT, and FD Teams were mobilized in the field. **End of Real Event.**

A total of thirty-eight (39) individuals supported this response including: Alpine IMT members, FD, MERT, SRT, and Anchorage FST members (Family Assistance, PIO, Legal, and an ICS specialist).

The successful resolution of this event satisfied 10 of the 15 NPREP components, and the Real Event meets the Unannounced Exercise requirement as defined in the NPREP Guidelines which COP complies with per the Alpine ODPCP and Alpine EAP.

## SRT Mobilization for Spill Response

The Alpine SRT is comprised of approximately 31 members who train every Monday throughout the year. The SRT was utilized to assist Alaska Clean Seas (ACS) with clean-up of various incidents within the operating area during the year. Inviting the SRT to assist with clean-up provides an opportunity for members to exercise the deployment of equipment and tactics necessary for successful resolution of an event.

## 2017 Qualified Individual Notification Exercises

Qualified Individual notification exercises were conducted on the following 2017 dates:

- March 20
- June 30
- September 27
- December 29 (fulfilled requirement of notification afterhours)

# G. CONSTRUCTION AND TERMINATION

*ALPINE OIL PIPELINE ADL 415701*
*ALPINE UTILITY PIPELINE ADL 415857*
*ALPINE DIESEL PIPELINE ADL 415932*

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# CONSTRUCTION AND TERMINATION

## CONSTRUCTION

No pipeline construction activities were performed. There are no plans to perform any pipeline construction activities in 2017.

## TERMINATION

In 2017, no pipeline termination activities were performed; however, on November 29, 2017, CPC received the SPC's approval for the Release of Interest in certain State Lands held by the Alpine Leases.

# H. THIRD-PARTY RIGHT-OF-WAY ACCESS

| | |
|---|---|
| *ALPINE OIL PIPELINE* | *ADL 415701* |
| *ALPINE UTILITY PIPELINE* | *ADL 415857* |
| *ALPINE DIESEL PIPELINE* | *ADL 415932* |

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# THIRD-PARTY RIGHT-OF-WAY ACCESS

Prior to performing any work within a ROW, Third-parties are required to secure authorization from the Lessee for access to the ROW. The SPCS requires the Lessee to notify them once an authorization has been issued to the Third-party for access. Table H-1 provides a list of non-objection and routine maintenance authorization letters processed by the Lessee for Third-party access to an Alpine Pipelines ROW.

Table H-1. Non-Objection and Routine Maintenance Letters

| Activity Description | Letter | | | Activity Completion | | |
|---|---|---|---|---|---|---|
| | Date | Non-Objection | Routine Maintenance | Planned | | Actual |
| | | | | Start | Finish | Closure[1] |
| **CONOCOPHILLIPS ALASKA, INC.** | | | | | | |
| GMT-1 Water Injection Pipeline Construction | 01/15/17 | ■ | | 08/01/16 | 09/07/17 | Open |
| CRU 2017 Annual Routine Maintenance | 01/04/17 | | ■ | 01/04/17 | 12/31/17 | Closed |
| **NORTH SLOPE BOROUGH** | | | | | | |
| Nuiqsut Coating Repair-Phase 1 | 03/07/17 | ■ | | 03/07/17 | 07/12/17 | Closed |

[1] Letters shown as "Open" in the table do not indicate that work is ongoing. A status of "Open" means the authorization has not moved through the closeout process. Formal closure includes notification from the designee to the DOT Compliance Specialist so a final inspection of the area can be scheduled. Final inspection is contingent on weather conditions such as snow cover and spring breakup. Once the final site inspection has been performed then the formal closeout of the LNO can be completed.

# I. OPERATIONS

*ALPINE OIL PIPELINE* *ADL 415701*
*ALPINE UTILITY PIPELINE* *ADL 415857*
*ALPINE DIESEL PIPELINE* *ADL 415932*

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# Operational Status

## ALPINE OIL PIPELINE

| | |
|---|---|
| **Commissioned** | 15 Nov 2000 |
| **Service** | Oil |
| **Availability** | 99.5% |

### Pressures and Temperatures

Pipeline pressures and temperatures relative to maximum operating pressure and the 3-day temperature limit demonstrates pipeline operations are within allowable parameters. Figures I-1.-I-3. are based on the minimum, average and maximum daily values logged by IP21, the computerized data acquisition system. Note the IP21 data typically shows a "spike" representing the maximum range of the instrument when it is taken offline during preventive maintenance and calibration. These spikes do not represent actual line pressures and temperatures.

### Shutdowns or Slowdowns

Table I-1. provides shutdown or slowdown periods that affected the AOP system. There was one planned shutdown of the Alpine Central Facility and AOP, and one slowdown from the Alpine Central Facility from maintenance resulting in a slowdown in the AOP.

Table I-1. Shutdowns and Slowdowns

| AOP Shutdowns or Slowdowns | | |
|---|---|---|
| | Shutdown | Slowdown |
| AOP | | |
| | 6/16 - 6/18 | 2/7 - 2/8 |
| Third-party Plant/Production Facility | | |
| Alpine Plant | | 2/7 - 2/8 |

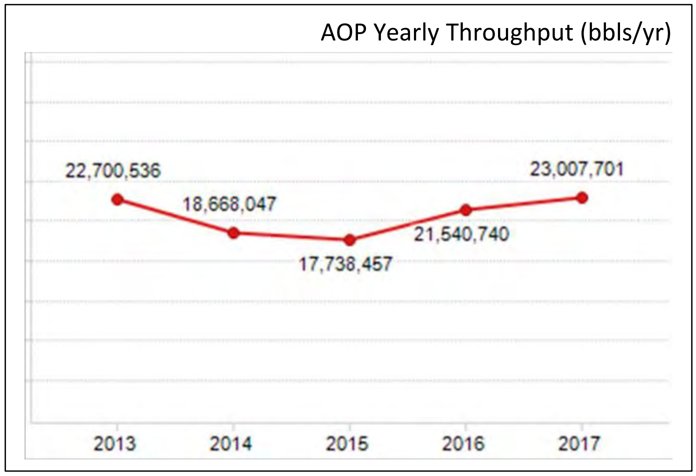


Figure I-1. Alpine Oil Throughput

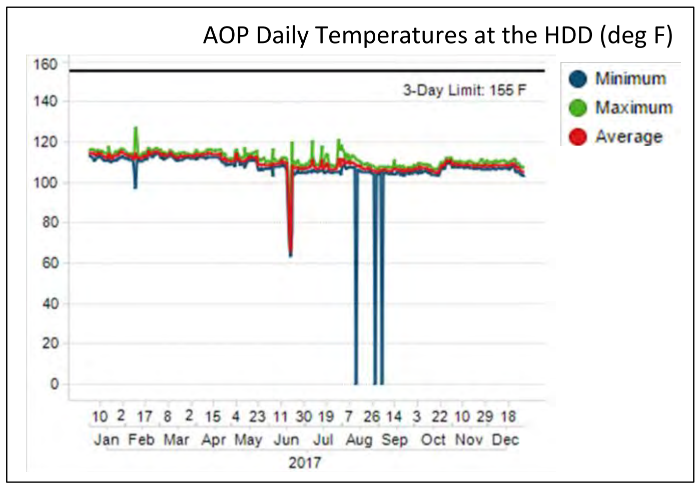


Figure I-2. Alpine Oil Temperature

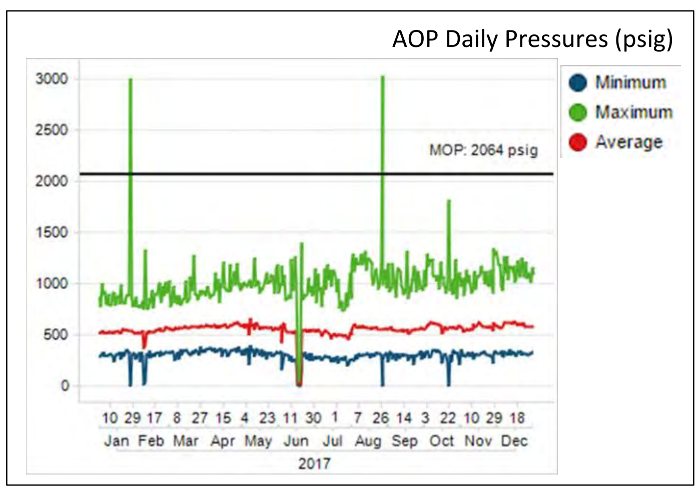


Figure I-3. Alpine Oil Pressure

## ALPINE UTILITY PIPELINE

| | |
|---|---|
| **Commissioned Service** | 21 June 2000 Natural Gas |
| **Converted Service** | 22 January 2001 Seawater |
| **Availability** | 100% |

### Pressures and Temperatures

Pipeline pressures and temperatures relative to maximum operating pressure and the 3-day temperature limit demonstrates pipeline operations are within allowable parameters. Figures I-4.-I-6. are based on the minimum, average and maximum daily values logged by IP21, the computerized data acquisition system. Note the IP21 data typically shows a "spike" representing the maximum range of the instrument when it is taken offline during preventive maintenance and calibration. These spikes do not represent actual line pressures and temperatures.

### Shutdowns or Slowdowns

Table I-2. provides shutdown or slowdown periods that affected the AUP system. There were no shutdowns or slowdowns.

Table I-2. Shutdown and Slowdowns

| AUP Shutdowns or Slowdowns | | |
|---|---|---|
| | Shutdown | Slowdown |
| AUP | | |
| - | - | - |
| Third-party Plant/Production Facility | | |
| - | - | - |

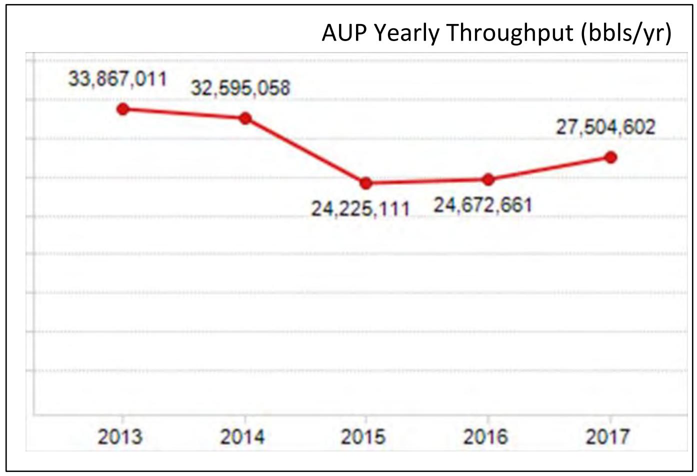


Figure I-4. Alpine Utility Throughput

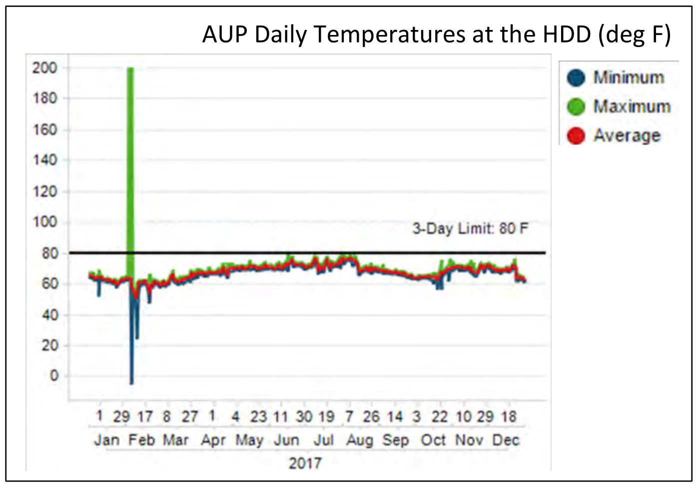


Figure I-5. Alpine Utility Temperature

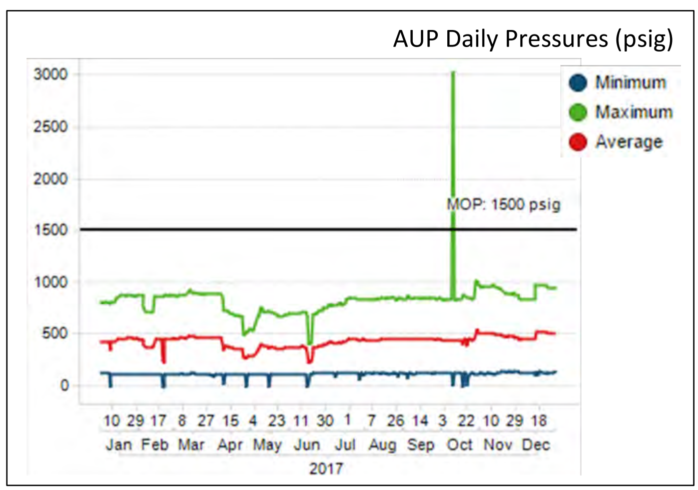


Figure I-6. Alpine Utility Pressure

## ALPINE DIESEL PIPELINE

| | |
|---|---|
| **Commissioned** | 20 May 1999 |
| **Service** | Diesel |
| **Converted** | 02 July 2003 |
| **Service** | Products |
| **Configuration** | |
| Below Grade | 20 May 1999 |
| Above Grade | 06 March 2001 |
| **Shipments (other than diesel)** | |
| Mineral Oil[1] | 1 |
| New Products[2] | 0 |
| **Availability** | 100% |

**Pressures and Temperatures**

Pipeline pressures and temperatures relative to maximum operating pressure and the temperature limit demonstrates pipeline operations are within allowable parameters. Figures I-7.-I-9. are based on average daily values compiled by IP21, the computerized data acquisition system. Anomalies in the data, where they may exist, are noted on the graphs. Note the IP21 data typically shows a "spike" representing the maximum range of the instrument when it is taken offline during preventive maintenance and calibration. These spikes do not represent actual line pressures and temperatures.

**Shutdowns or Slowdowns**

Table I-3. provides shutdown or slowdown periods that affected the ADP system. Note that the pipeline connector does not require diesel continuously and the line flowrate is determined by their need.

Table I-3. Shutdowns and Slowdowns

| ADP Shutdowns or Slowdowns | | |
|---|---|---|
| | Shutdown | Slowdown |
| ADP | | |
| | - | - |
| Third-party Plant/Production Facility | | |
| Alpine Plant | - | - |

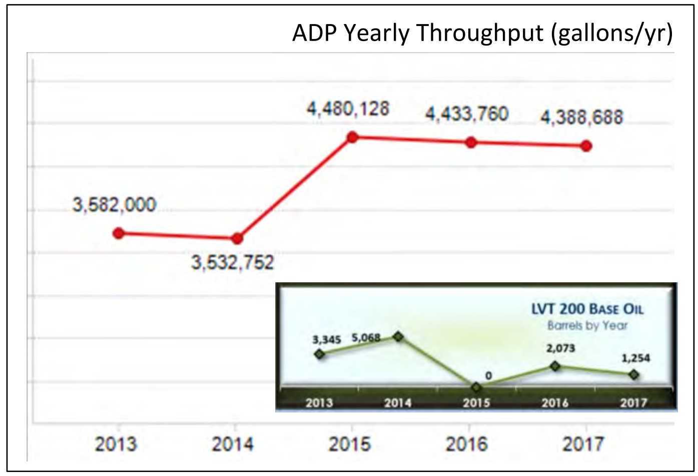


Figure I-7. Alpine Diesel Throughput

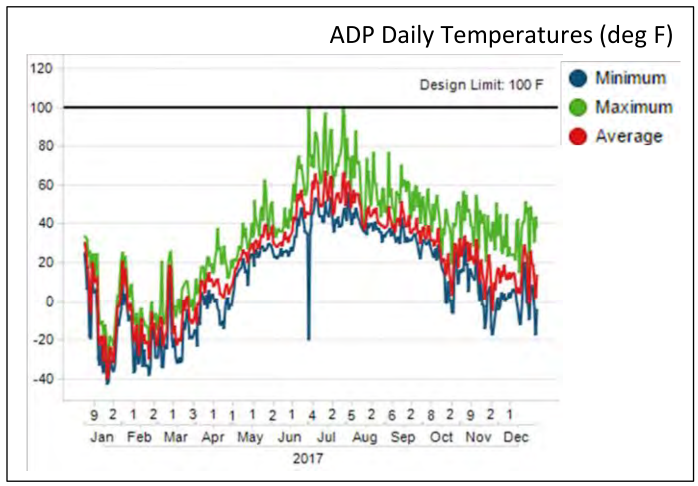


Figure I-8. Alpine Diesel Temperature

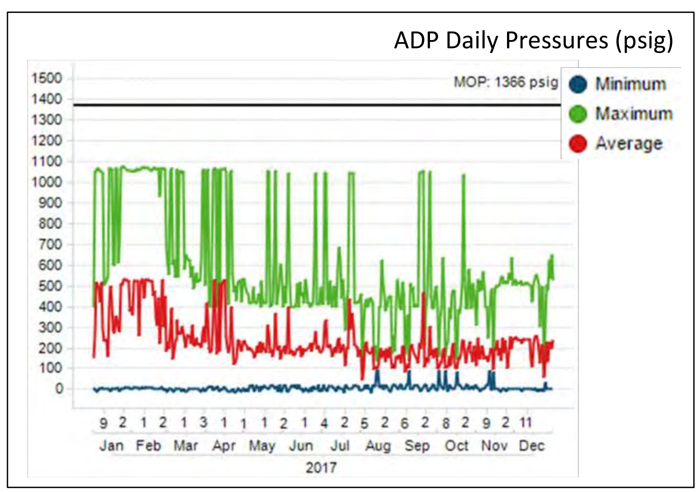


Figure I-9. Alpine Diesel Pressure

[1] See Section K for details.
[2] New products require technical analysis prior to shipping.

# SYSTEM MODIFICATIONS AND IMPROVEMENTS

## ACCOMPLISHMENTS AND PLANS

This section provides a summary of significant system modifications and improvements accomplished in this reporting year or planned

### ALPINE OIL PIPELINE

#### Tuned Vibration Absorbers (TVAs)

Installed tuned vibration absorbers from VSM 2906 to the CPF2 pad. Installation was completed during the first quarter of the 2017 ice road season.

#### Flow Computer Upgrade

Replaced two sales oil metering skids FMC-Smith Sybertrol flow computers with Emerson ROC flow computers. Installation will be completed by the end of 2018.

#### Alpine Meter Skid Upgrade

Added pressure and temperature sensors on each individual meter run to mitigate the impact of sensor failure and calibration activities on calculated oil volumes. This work will begin during the first quarter of 2018 and be completed by the end of 2018.

### ALPINE DIESEL PIPELINE

#### Road Crossing Casing Replacement and Pipeline Reroute

Phase 1, installation of new 8-inch casing at five road crossing locations along the ADP ROW was completed the fourth quarter of 2017. Phase 2 includes intalling new FBE coated pipe to prevent future atmospheric corrosion through the five new cased crossings. The pipe installation and casing surveys will be completed in 2018.

### THIRD-PARTY REQUESTS

#### Brooks Range Petroleum Company, Mustang Project

Brooks Range Petroleum Company requested connections to the AOP and AUP. For more information see the Division of Oil and Gas, *Approval of the Southern Miluveach Unit Term Extension and Revised Plan of Development*, issued on March 30, 2016 at:
http://dog.dnr.alaska.gov/documents/units%5C2016/20160330_sv_unitextn_approved.pdf

# J. MAINTENANCE

*ALPINE OIL PIPELINE ADL 415701*
*ALPINE UTILITY PIPELINE ADL 415857*
*ALPINE DIESEL PIPELINE ADL 415932*

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# MAINTENANCE

Alpine pipelines annual maintenance includes routine inspections, preventive and corrective maintenance, and other routine program, plan, and process review activities. Table J-1 summarizes work done to repair or correct deficiencies identified during preventative maintenance or inspections, or that was found during normal operations. Refer to *Section M. Surveillance and Monitoring* for activities that generally are not managed by work order number.

Table J-1. Corrective Maintenance Summary

## Corrective Maintenance

| Alpine Diesel Pipeline |
|---|
| Repaired a U-bolt |
| Repaired pipeline supports |
| Installed new casing for road crossings |
| Repaired AL-02 heat trace |
| Repaired AL04 gas head |
| Installed a blanket around temp indicator |
| Completed annual surveillance repairs |

| Alpine Oil Pipeline |
|---|
| Completed annual surveillance repairs |
| Repaired VSM 2346-2367 |
| Repaired VSM 2854 |
| Checked heat trace operation |
| Repaired flow valve leak by |
| Repaired AL-01 ROV-AL9338 air leak |

| HDD |
|---|
| Completed annual surveillance repairs |
| Repaired HDD casing end seals |
| Troubleshooted HDD East Thermistor TE9 |
| Tightened loose bolts on signage |
| Replaced missing signs |

| Alpine Utility Pipeline |
|---|
| Installed VSM F2-15, F2-31 and 2070 sleeves |
| Installed recycle shield |
| Cleaned sump pump discharge |
| Completed annual surveillance repairs |
| Repaired malfunctioning gas detector |
| Replaced AL06 rec. line valve |
| Addressed issue with leak detect flow meter |
| Replaced SIS power supply |
| Repaired CFA2 weld locations 50/52 |
| Replaced emergency light fixture |

Table J-2. Preventive Maintenance Summary

## Preventive Maintenance

| DESCRIPTION QUANTITY/LOCATION | REPORTABLE CONDITIONS OR RATIONALE | PIPELINE | FREQUENCY |
|---|---|---|---|
| **COMMUNICATIONS** | | | |
| **Backup Comm Systems-Process Safety Systems** | ▶ Functional check the back-up safety instrumented system com circuits | All | Annually |
| **Backup SCADA Server** | ▶ Test the backup SCADA server | All | Annually |
| **Communications Plan-Ops Annual Drill** | ▶ Test and verify comm. plan in support of safe manual pipeline operations | All | Annually |
| **Communications Systems-Telecom. Equip.** | ▶ Ensure systems between control room and remote locations | All | Annually |
| **CONTROL ROOM MANAGEMENT** | | | |
| **Alarm Activity Review** | ▶ Review safety related alarm status and activity for the Pipeline | All | Monthly |
| **Alarm Management Plan** | ▶ Evaluate the effectiveness of the Alarm Management Plan | All | Annually |
| **Controller Training Program** | ▶ Review training program for completeness and improvements | All | Annually |
| **Controller Workload** | ▶ Review to ensure no adverse impacts to the Controller to safely operate the pipelines | All | Annually |
| **CORROSION CONTROL** | | | |
| **Below Grade Casings** | ▶ Ensure casing is free of obstructions | ALL | Annually |
| **HDD Cathodic Protection System** | ▶ Confirm proper functioning of CP system<br>▶ Includes casing isolation testing | ALL | Annually |
| **HDD Cathodic Protection System** | ▶ Confirm proper functioning of rectifiers | ALL | 2 months |
| **Cleaning Pigs** | ▶ Ensure the pipeline is free of solids, deposits, and water dropout | ADP | Quarterly |
| | | AOP | Monthly |
| | | AUP | 3 weeks |
| **Pipeline Repair Kit** | ▶ Ensure repair sleeves/clamps meet all required Eng. specifications. | ALL | 2 years |
| **ENVIRONMENTAL** | | | |
| **Oil Discharge Prevention and Contingency Plan** | ▶ Obtain approvals from ADEC, EPA and DOT-PHMSA | ALL | 5 years |
| **FIRE PROTECTION** | | | |
| **F&G Function Test - Fire Zones 39, 40, 41, 42, 52** | ▶ Function check the fire protection control system to ensure the system will function as designed during alarm conditions | ALL | Annually |

| | | | |
|---|---|---|---|
| **HDD RIVER CROSSING** | | | |
| **Electrical Isolation Test and End Seal** | ▶ Inspect for migration of moisture or liquids in casing<br>▶ Confirm proper functioning | ALL | Annually |
| **Emissions** | ▶ Inspect for signs of oil and coolant leakage | ALL | Quarterly |
| **Fire or Fire Hazard** | ▶ Replace extinguishers with re-certified extinguishers | ALL | Annually |
| **LAUNCHER / RECEIVER** | | | |
| **Launcher (Alpine)** | ▶ Inspect and Service | AOP | 3 years |
| **Launcher (CPF2)** | ▶ Inspect and Service | AUP | 3 years |
| **Receiver (Alpine)** | ▶ Inspect and Service | AUP | 3 years |
| **Receiver (CPF2)** | ▶ Inspect and Service | AOP | 3 years |
| **LEAK DETECTION** | | | |
| **Depressure - AHF to Alpine** | ▶ Calibrate and function check | ADP | Annually |
| **Flow Meter - Crude from Alpine** | ▶ Calibrate and function check | AOP | Annually |
| **Flow Meter - Seawater to Alpine** | ▶ Calibrate and function check | AUP | Annually |
| **HDD Leak Detection** | ▶ Calibrate and function check | ALL | Annually |
| **Pipeline Leak Detection** | ▶ Ensure leak detection system is capable of promptly detecting a leak<br>▶ Ensure the system has the continuous capability to detect a daily discharge equal to not more than 1% of daily throughput | ADP | 5 years |
| **Pipeline Leak Detection** | ▶ Ensure leak detection system is capable of promptly detecting a leak<br>▶ Ensure the system has the continuous capability to detect a daily discharge equal to not more than 1% of daily throughput | AOP, AUP | 2 years |
| **Pipeline Leak Detection Inst. - ADP to ACF-1** | ▶ Calibrate and function check | ADP | Annually |
| **Pipeline Leak Detection Instr. - SW to ACF-1** | ▶ Calibrate and function check | AUP | Annually |
| **METERS / PROVERS** | | | |
| **Alpine Crude Oil Meter Prover** | ▶ Calibrate temperature and pressure transmitters | AOP | Annually |
| **Alpine Crude Oil Meter Prover - Water Draw** | ▶ Certify the stationary prover using the water draw method. | AOP | 3 years |
| **OVERPRESSURE PROTECTION** | | | |
| **Overpressure Protection - AHF Transfer Pumps** | ▶ Calibrate and function check high pressure OSD function | ADP | Annually |
| **Overpressure Protection - Alpine** | ▶ Calibrate and function check OSD and SESD functions | AOP | Annually |
| **Overpressure Protection - Alpine** | ▶ Calibrate and function check PSVs | ALL | Annually |
| **Overpressure Protection - CPF2** | ▶ Calibrate and function check high pressure OSD function | AOP | Annually |
| **Overpressure Protection - CPF2** | ▶ Calibrate and function check PSVs | ADP | Annually |

| | | | |
|---|---|---|---|
| **Overpressure Protection - CPF2** | ► Inspect spring operated PSVs | AUP | Annually |
| **Overpressure Protection - CPF2 Break Out Tank** | ► Calibrate and function check PSVs | AOP | Annually |
| **Overpressure Protection - CPF2 Divert Line** | ► Calibrate and function check PSVs | AOP | Annually |
| **Overpressure Protection - CPF2 Module AL06** | ► Calibrate and function check PSVs | AUP | Annually |
| **Overpressure Protection - CPF2 Pig L/R** | ► Calibrate and function check PSVs | ADP, AOP | Annually |
| **Overpressure Protection - Mainline PCV** | ► Verify the proper operation of PCV-61067 | ADP | Annually |
| **VALVES** | | | |
| **Mainline Auto. Block Valves – ACF-1 to CPF2** | ► Inspect and ensure proper functioning | ALL | 6 months |
| **Mainline Manual Valves – Alpine & CPF2** | ► Inspect and ensure proper functioning | ALL | 6 months |
| **Secondary Manual Valves – Alpine & CPF2** | ► Inspect and ensure proper functioning | ALL | 6 months |
| **PROGRAMS** | | | |
| **Communication -- Public Education** | ► Conduct public educational and awareness programs in English and other languages commonly understood by a significant number of non-English speaking populations | ALL | Annually |
| **DOT Annual Report - Liquids** | ► Compile the required information and submit DOT FORM PHMSA F 7000-1.1 by June 15 for the preceding calendar year | ALL | Annually |
| **DOT/Ops Personnel Performance** | ► Review actions taken by personnel during normal ops/maint<br>► Review actions taken by personnel during an abnormal or emergency | ALL | Annually |
| **Drug and Alcohol - Contractor Compliance** | ► Verify Contractors are listed as satisfactory within the NCMS database | ALL | 6 months |
| **Drug and Alcohol Testing** | ► Verify Supervisors are trained per 199.241<br>► Verify completion of random tests<br>► Verify contractor companies are complying | ALL | Annually |
| **Facility Security Program** | ► Conduct annual review of the facility Security Plan | ALL | Annually |
| **Integrity Management Program** | ► Complete the High Consequence Area evaluation, Risk Assessment evaluation, and Program and Performance Measure evaluation.<br>► Make the NPMS notification. | ALL | Annually |
| **O&M 3-yr Program and Process** | ► Review of the programs/ procedures for accuracy and effectiveness | ALL | 3 years |
| **O&M Program and Process** | ► Review of the operating manuals, programs, procedures for completeness, accuracy and effectiveness | ALL | Annually |
| **Operator Qualification Program** | ► Review the SkillsNOW Operator Qualification records database.<br>► Conduct program performance monitoring. | ALL | Annually |

| | | | |
|---|---|---|---|
| **Operator Qualification Program** | ►Conduct an Operator Qualification (OQ) effectiveness survey to identify potential improvements. | ALL | 3 years |
| **Public Awareness Program - Evaluation / Communications** | ►Develop and revise plans, programs, procedures, and deliverables used to ensure the communication and effective implementation of PAP requirements.<br>►Prepare and ensure the distribution | ALL | Annually |
| **Public Awareness Program** | ►Review the CPAI Public Awareness Program (PAP) | ALL | 4 years |
| **SPCS Annual Report** | ►Prepare and/or review assigned sections of the Report | ALL | Annually |
| **RIGHT-OF-WAY** | | | |
| **Road Crossing Coverage** | ►Casings have a minimum coverage depth less than 12 inches<br>►Maximum grade of the modified roadway is greater than 3%<br>►Side slopes do not match existing slopes | ALL | 2 years |

# K. Events, Incidents, and Issues

| | |
|---|---|
| *Alpine Oil Pipeline* | *ADL 415701* |
| *Alpine Utility Pipeline* | *ADL 415857* |
| *Alpine Diesel Pipeline* | *ADL 415932* |

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# EVENTS, INCIDENTS, AND ISSUES

As the AOP and AUP moved into their 17TH year of operational status and the ADP into its 18TH, the following events, incidents, or issues may have required review, analysis, or resolution.

## UNINTENDED EVENTS

### ALPINE OIL PIPELINE

There were no overpressure or integrity issues or unintended shutdowns due to pipeline operations; however, there were third-party plant or production facility slowdowns and shutdowns that affected rates through the AOP, during 2017. See Section I, Operations, for more information.

### ALPINE UTILITY PIPELINE

There were no overpressure or integrity issues or unintended shutdowns due to pipeline operations or third-party plant or production facility shutdowns or slow-downs.

### ALPINE DIESEL PIPELINE

There were no overpressure or integrity issues due to pipeline operations or third-party plant or production facility activities; however, data obtained from a periodic atmospheric monitoring event prompted a conservative approach to how the ADP would be operated using a single shipping pump and segment replacements planned for early 2018. See Section I, Operations, for more information.

## RIGHT-OF-WAY INCIDENTS

There were no incidents within the ROWs.

# L. Right-of-Way Lease Performance

*Alpine Oil Pipeline* *ADL 415701*
*Alpine Utility Pipeline* *ADL 415857*
*Alpine Diesel Pipeline* *ADL 415932*

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## ACTIVITIES AND RESULTS SUMMARY

To provide the status of various ROW Lease and Stipulation requirements not addressed elsewhere in this report, Table L-1 *ROW Activities and Results Summary* identifies:

- The Section or Stipulation number and a brief requirements summary
- How often the requirement must be addressed
- The date the requirement was last addressed, will be addressed again, or the current document expires
- Current year activities and results

## COMPLIANCE MATRIX

☒ **New** / Revised

After careful review of the *Right-of-Way Agreement Compliance Matrix*, the tool was found to be obsolete. The tool has subsequently been replaced with a more effective compliance tool, the *DOT and ROW Compliance Tool*. The *DOT and ROW Compliance Tools* functionality ensures that all Federal and State pipeline requirements are being met in the time frame required by regulation. The tool has a built-in tracking function that alerts users when a task is due and provides the ability to generate reports, charts and graphs and utilize GIS shapefiles.

The *DOT and ROW Compliance Tool* will be reviewed annually to ensure that changes in regulation and/or lease commitments are captured and adequately addressed.

Table L-1. Alpine Pipelines Right-of-Way Performance Matrix

## *ALPINE PIPELINES*

| REQUIREMENTS | | | PIPELINES | | | FREQUENCY | | | | | | | STATUS | | | ACTIVITIES / RESULTS | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SECTION / STIPULATION | | REQUIREMENT | Alpine Oil | Alpine Utility | Alpine Diesel | Quarterly | Annual | 5 Years | 10 Years | 30 Years | Continuous | Conditional | Last Activity | Next Activity | Expiration | DESCRIPTION / COMMENTS | NOTE |
| **LEASE / GRANT** | | | | | | | | | | | | | | | | | |
| 2 | **Duration and Renewal** | ▶Intent to renew notification, 6 months prior to Lease/Grant expiration. | ■ | | | | | | | ■ | | | 09/05/03 | 12/15/18 | - | ▶Alpine Pipelines Renewal notification provided to the SPCS at the 2Q17 Coordination Meeting , June 2018. | |
| | | | | ■ | | | | | ■ | | | | 01/06/99 | 01/05/19 | - | | |
| | | | | | ■ | | | | | ■ | | | 09/05/03 | 12/15/18 | - | | |
| 3(b) | **Rental Payments** | ▶Annual rental payments on Lease/Grant Anniversary Date. | ■ | | ■ | | ■ | | | | | | 11/2017<br>11/2017 | 11/2018<br>11/2018 | -- | ▶Paid Annual Rental: Oil = $108,745; Diesel = $108,638; Utility = $108,724 | |
| | | | | ■ | | | ■ | | | | | | 12/2017 | 12/2018 | -- | | |
| 3(d) | **Rental Adjustment / Appraisal** | ▶Annual rental payment adjustment based on the appraised fair market rental value every 5th Lease/Grant Anniversary Date. | ■ | ■ | ■ | | | ■ | | | | | 06/30/16 | 2018 | -- | ▶DNR Commissioner Denied Appeal, June 2016<br>▶5-yr. appraisals due 2018/2019<br>▶Lease renewals due 2018/2019 | |
| 8(a)<br>8(g) | **Common Carrier Operations** | ▶Performance of all functions undertaken under lease as a common carrier.<br>▶Operation in accordance with applicable state laws and lawful regulations and orders of the Regulatory Commission of Alaska. | ■ | | | | | | | | ■ | | -- | -- | -- | ▶Continued to perform all functions as a common carrier. | |
| 8(j)<br>8(d)<br>8(a)(6) | **Registered Agent** | ▶Appointment of a registered agent in Alaska to receive service of notices, regulations, decisions, and orders of the Commissioner. | ■ | ■ | ■ | | | | | | | ■ | 12/10/12 | -- | -- | ▶Barry Romberg continues carrying out appointed responsibilities. | |
| 9 | **Contractors Agents Employees** | ▶Contractors, agents, and employees provide indemnities, insurance, and waivers to include the State. | ■ | ■ | ■ | | | | | | ■ | | 09/15/04 | -- | -- | None | |
| 10 | **Worker's Compensation Insurance** | ▶ Provide and maintain workers' compensation insurance as required by state and federal law. | ■ | ■ | ■ | | ■ | | | | | | 03/2017 | 03/2018 | 03/2018 | ▶Secured Employers Notice of Insurance | |
| 12 | **Additional Insured** | ▶ Name the State as an additional insured on all such insurance policies obtained and maintained by the Lessee. | ■ | ■ | ■ | | | | | | | ■ | 07/2016 | 07/2019 | -- | ▶Confirmed ConocoPhillips and its affiliates are insured under a worldwide insurance program subject to a $125 million liability and $150 million property risk, per occurrence deductible | |

Table L-1. Alpine Pipelines Right-of-Way Performance Matrix

## *ALPINE PIPELINES*

| REQUIREMENTS | | | PIPELINES | | | FREQUENCY | | | | | | | STATUS | | | ACTIVITIES / RESULTS | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SECTION / STIPULATION | | REQUIREMENT | Alpine Oil | Alpine Utility | Alpine Diesel | Quarterly | Annual | 5 Years | 10 Years | 30 Years | Continuous | Conditional | Last Activity | Next Activity | Expiration | DESCRIPTION / COMMENTS | NOTE |
| **24** | **Expense Reimbursement** | ► Reimbursement for design review and oversight activities. | ■ | ■ | ■ | ■ | | | | | | | 1Q2017 | 1Q2018 | -- | Quarterly invoices paid to the SPCS:<br>Letter 16-329-AS $8,807.95(1Q17)<br>Letter 17-003-AS $12,681.69(2Q17)<br>Letter 17-095-AS $22,146.19(3Q17)<br>Letter 17-217-AS $23,960.00(4Q17)<br>Letter 17-235-AS $22,137.32(5Q17)<br>**ALPINE TOTAL: $100,733.15** | |
| **25** | **Transfer of Interest** | ► Approval of Ownership transfers of greater than or equal to 30%. | ■ | | | | | | | | | ■ | 10/07/10 | -- | -- | None | |
| | | | | ■ | | | | | | | | ■ | -- | -- | -- | None | |
| | | | | | ■ | | | | | | | ■ | -- | -- | -- | None | |
| **26** | **Default and Forfeiture** | ► ROW Lease forfeiture if unable to comply with Lease/Grant. | ■ | | | | | | | | | ■ | -- | -- | -- | None | |
| | | | | ■ | | | | | | | | ■ | -- | -- | -- | None | |
| | | | | | ■ | | | | | | | ■ | -- | -- | -- | None | |
| **29** | **Release of Interests** | ► Execute and deliver a valid instrument of release in recordable form, which must be executed and acknowledged with the same formalities as a deed. | ■ | ■ | ■ | | | | | | | ■ | 11/29/17 | 2018 | -- | CPC submitted a request for partial release of interest in state lands held under the Alpine Pipelines leases July 2015. The SPC approved the request November 2017. Survey of the new ROW boundary is planned for CY2018. | |
| **30** | **Authorized Representatives** | ► Appointment of an authorized representative to administer the lease/grant. | ■ | ■ | ■ | | | | | | | ■ | 12/2017 | -- | -- | Updates to Officer, Designation of Registered Agent and Authorized Representative provided to the SPCS. | |
| **30** | **Field Representatives** | ► Appointment of field representatives to at all times be available in the immediate area of the right-of-way. | ■ | ■ | ■ | | | | | | | ■ | 10/12/15 | -- | -- | None | |
| **32** | **Local Hire** | ► Evidence that hiring and employing local Alaska residents and companies is fostered. | ■ | ■ | ■ | | | | | | ■ | | 01/01/16 | 01/01/17 | -- | ►Continued to foster local hire practices. | |
| **33** | **Non-Discrimination** | ► Evidence that Lessee/Grantee does not discriminate against employee or applicants as set out in AS 18.80.220. Provisions are prominently posted. | ■ | ■ | ■ | | | | | | ■ | | 01/01/16 | 01/01/17 | -- | ►Continued implementing "*Equal Employment Opportunity Policy*"<br>►Confirmed "*Equal Employment Opportunity is THE LAW*" information is posted | |
| **34** | **Correspondence** | ► Correspondence delivery addresses. | ■ | ■ | ■ | | | | | | | ■ | 12/2017 | -- | -- | ►Change in billing contacts notification made | |
| **42** | **Recording** | ► Record legal instruments in the Barrow Recording District, State of Alaska. | ■ | ■ | ■ | | | | | | | ■ | 02/09/11 | -- | -- | None | |

*ALPINE PIPELINES*

## STIPULATIONS: GENERAL

| SECTION / STIPULATION | | REQUIREMENT | Alpine Oil | Alpine Utility | Alpine Diesel | Quarterly | Annual | 5 Years | 10 Years | 30 Years | Continuous | Conditional | Last Activity | Next Activity | Expiration | DESCRIPTION / COMMENTS | NOTE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1.13.1** | **Material Storage** | ▶Authorization before storing machinery, equipment, tools, materials, and structures not being used on the right-of-way.<br>▶Notice of storage location expansion or change. | ■ | ■ | ■ | | ■ | | | | | ■ | 11/01/17 | -- | -- | ▶See *Section M* for Alpine's annual inventory inspection | |
| **1.14** | **Annual Comprehensive Reports** | ▶Lessee/Grantee must submit a comprehensive report to the Commissioner on the state of the Pipeline System and its Pipeline Activities. | ■ | ■ | ■ | | ■ | | | | | | 02/28/17 | 03/01/18 | -- | ▶CPC submitted the *2016 Annual Comprehensive Report* to the SPCS on February 28, 2017. SPCS acknowledged receipt of the report on May 23, 2017 at the 2Q17 Coordination Meeting. | |

## STIPULATIONS: ENVIRONMENTAL

| SECTION / STIPULATION | | REQUIREMENT | Alpine Oil | Alpine Utility | Alpine Diesel | Quarterly | Annual | 5 Years | 10 Years | 30 Years | Continuous | Conditional | Last Activity | Next Activity | Expiration | DESCRIPTION / COMMENTS | NOTE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2.1** | **Environmental Briefing** | ▶Develop and provide environmental briefings for supervisory, field personnel, and field representatives.<br>▶Briefings communicate right-of-way lease and environmental permit requirements. | ■ | ■ | ■ | | ■ | | | | | ■ | 2017 | 2018 | -- | ▶4 ALP CPAI employees attended Alpine Right-of-Way Training<br><br>▶29 ALP CPAI employees will attended 2018 Alaska Safety Handbook Training (CPA-REQ-042-MIX)<br><br>▶4 ALP CPAI employees attended Hazcom Program Training (CPA-REQ-022-MIX)<br><br>▶26 ALP CPAI employees attended Hazwoper First Responder Awareness or Operations Training (CPA-REQ-024-MIX) | |
| **2.2** | **Pollution Control** | ▶Authorization to significantly change the temperature of natural surface or ground water that may adversely affect the natural surface or ground water. | ■ | ■ | ■ | | | | | | | ■ | -- | -- | -- | None | |
| **2.3.1.1.1** | **Ice Roads, Ramps, and Pads** | ▶Authorization to construct ice roads, snow/ice ramps, and ice work pads. | ■ | ■ | ■ | | | | | | | ■ | 12/13/97 | -- | Life of Field | | 1 |

Table L-1. Alpine Pipelines Right-of-Way Performance Matrix

## *ALPINE PIPELINES*

| SECTION / STIPULATION | | REQUIREMENT | Alpine Oil | Alpine Utility | Alpine Diesel | Quarterly | Annual | 5 Years | 10 Years | 30 Years | Continuous | Conditional | Last Activity | Next Activity | Expiration | DESCRIPTION / COMMENTS | NOTE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2.7** | **Disturbance or Use of Natural Waters** | ▶ Authorization to create new lakes, drain existing lakes, significantly divert natural drainage and surface runoff permanently alter stream or ground water hydrology, or disturb significant areas of stream beds require authorization. | ■ | ■ | ■ | | | | | | | ■ | -- | -- | -- | None | |
| **2.8.1** | **ROW Traffic** | ▶ Authorization to operate mobile ground equipment on State Lands in the Leasehold. | ■ | ■ | ■ | | | ■ | | | | ■ | 10/01/15 | 01/08/20 | Life of Field | ▶Permit LAS 23007: reissue application received by DMLW 10/01/15. DMLW issues permit 01/08/15 for summer and winter off-road travel through 01-06-2020. | |
| | | | | | | | | ■ | | | | ■ | 01/07/15 | 01/06/20 | Life of Field | ▶LAS 25360 Ice road and pad construction and use for the Alpine Development Project approved for reissue 01-07-2015 through 01-06-2020. | |
| **2.9** | **Use of Explosives** | ▶Authorization to blast under water or within one-quarter (1/8) mile of streams or lakes with identified fisheries or wildlife resources.<br>▶Approval of blast timing and location. | ■ | ■ | ■ | | | | | | | ■ | -- | -- | -- | None | |

# NOTES:

**(1)** **Ice Roads, Ramps, and Pads**

**ADF&G Fish Habitat Permits** authorize ice road construction and use, ice thickening, and equipment operations needed for pipeline placement and maintenance of the pipeline system during winter and summer within a 500-foot corridor upstream and downstream of the pipeline crossing:

- ▶FG97-III-0178 East Fork Kalubik Creek
- ▶FG97-III-0179 Crossing at Kalubik Creek
- ▶FG97-III-0180 Crossing at Trouble Creek
- ▶FG97-III-0181 Crossing at Miluveach River
- ▶FG97-III-0182 Crossing at Kachemach River
- ▶FG97-III-0183 Crossing at Kachemach, Tributary 3
- ▶FG97-III-0184 Crossing at Unnamed Creek
- ▶FG97-III-0185 Crossing at Colville River
- ▶FG97-III-0187 Crossing of Waters in the Colville River Delta

# M. Surveillance and Monitoring

| | |
|---|---|
| *Alpine Oil Pipeline* | *ADL 415701* |
| *Alpine Utility Pipeline* | *ADL 415857* |
| *Alpine Diesel Pipeline* | *ADL 415932* |

ConocoPhillips

# PROGRAMS

## ALPINE PIPELINES SURVEILLANCE AND MONITORING PROGRAM

☐ New / Revised

Approved 15 February 2013, the Alpine Pipelines *Surveillance and Monitoring Program*, Edition 1 Rev 1, identifies threats to personnel safety, the environment, or pipeline integrity; and, in conjunction with the *Maintenance Program* (Section J) ensures effective intervention. The programs consist of a combination of aerial and ground-based techniques, routine and corrective maintenance, and inspection tasks.

Table M-1 provides a list of the principle procedures that define how personnel conduct surveillance, monitoring, and maintenance activities applicable to the arctic environment as required by the Alpine pipelines ROW Leases and Grant, Section 14c, Exhibit A. and Stipulation 1.6. In addition, the Operator performs annual wildlife and avian analysis to understand the distribution, abundance, and productivity of the various species in the Alpine Development and ensure there are no significant impacts to wildlife and the environment resulting from pipeline operations.

Table M-1. Principle Surveillance, Monitoring, and Maintenance Programs and Procedures

| Operations Manual[1], Standard Operating Procedures (APLM-0000-**-Suffix) | | New/Revised | | |
|---|---|---|---|---|
| Suffix | Title | AOP | AUP | ADP |
| 0042 | Corrosion Program | ☒ | ☐ | ☒ |
| **Revised:** Revision number 25 (AOP & ADP) dated July 2017. *What changes were made?* Operations added information for identifying locations within the pipeline insulation system that are considered susceptible to water ingress. | | | | |
| 0043 | Requirements for Maintenance and Repair | ☐ | ☐ | ☐ |
| **Revised:** No changes made during the year. | | | | |
| 0044 | Pipeline Surveillance Program[2] | ☐ | ☐ | ☐ |
| **Revised:** No changes made during the year. | | | | |
| 0045 | Cathodic Protection System —System Performance Testing | ☐ | ☐ | ☐ |
| **Revised:** No changes made during the year. | | | | |
| 0201 | Leak Detection System | ☒ | ☒ | ☒ |
| **Revised:** Revision number 15 (AOP), dated October 2017; 18 (AUP)/16 (ADP) dated 10/27/2017 *What changes were made?* Operations updated the description of RESET. Removed an outdated graphic; added a drawing reference and clarified language and removed redundancy throughout the document. | | | | |

*** AOP=Alpine Oil Pipeline, AUP = Alpine Utility Pipeline, ADP = Alpine Diesel Pipeline*

[1] Operations Manuals are reviewed annually

[2] The Surveillance and Monitoring Program is reviewed every three years

# RESULTS

## AERIAL AND FORWARD-LOOKING INFRARED SURVEILLANCE

The Operator routinely performs aerial, forward-looking infrared (FLIR), and ground-based surveillance, and supplements them based on specific need.  Figure M-1 provides a graphic representation of the number of aerial and FLIR surveillances performed monthly during the calendar year.

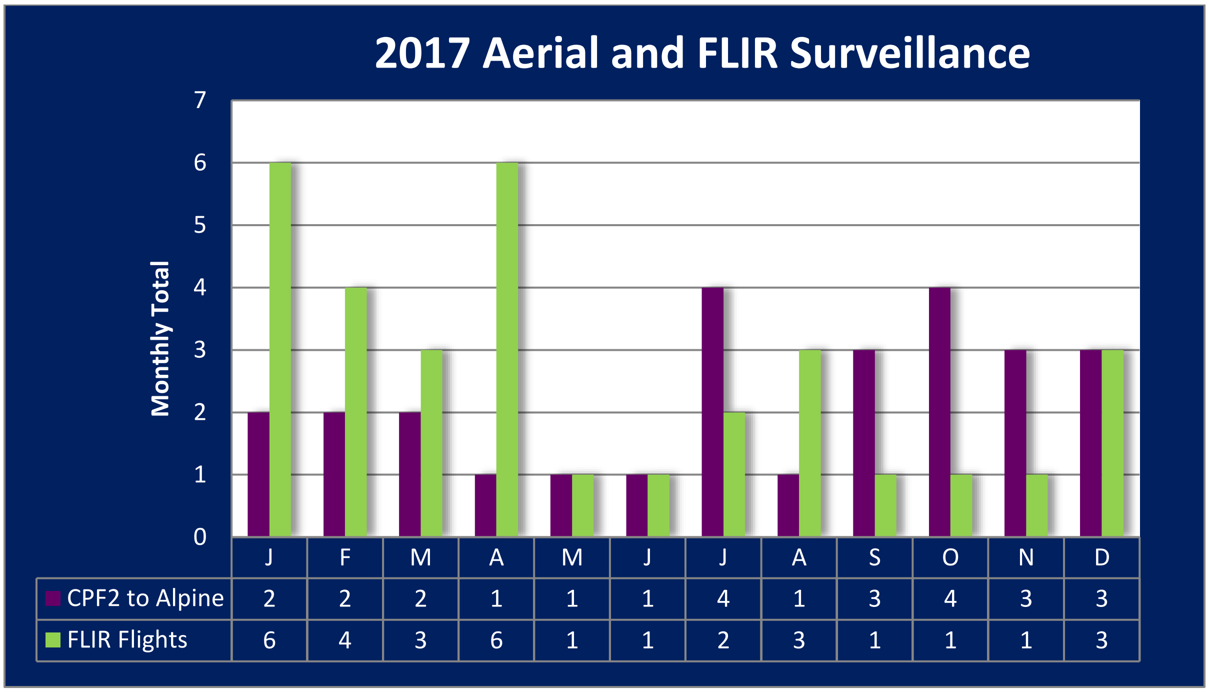


Figure M-1. FLIR and Aerial Surveillances

## SURVEILLANCE AND MONITORING SUMMARY

The *2017 Surveillance and Monitoring* matrix in Table M-1 provides a summary of each program element, the surveillance method used and the frequency of surveillance. The summary provides the reporting year results and includes any changes to the pipeline system, right-of-way or program when applicable. Refer to *Section J. Maintenance* for specific Plant Work Orders (PMO's) associated with performed or proposed activities.

Table M-1. Surveillance and Monitoring

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| **ABOVE GROUND PIPELINE** | | | | | | | |
| **Anchor Movement** | ▶Anchor out of level or broken welds. | ROW 1.6.1 (3) ROW 3.1.1 | Ground | Annually | ADP | 22311947 | ▶Annual inspection completed |
| | | | | | AOP | 22311950 | ▶Annual inspection completed |
| | | | | | AUP | 22311951 | ▶Annual inspection completed |
| **Component -- Damage** | ▶Structural damage to clamps, saddle assemblies, crossbeams/HSM, brackets and anchor assemblies | ROW 1.6.1 (3) | Ground | Annually | ADP | 22311947 | ▶Annual inspection completed |
| | | | | | AOP | 22311950 | ▶Annual inspection completed |
| | | | | | AUP | 22311951 | ▶Annual inspection completed |
| **FBE Coated Sleeves -- Damage** | ▶Damaged fusion bond epoxy (FBE) coated shrink sleeves at HDD transition | ROW 1.6.1 (3) ROW 1.7.2 | Ground | | ALL | 21779747 | ▶Annual inspection completed |
| **Ice and Snow Accumulation** | ▶Accumulations of ice or snow over the pipeline. | ROW 1.6.1 | Aerial | Weekly | ALL | 21878047 | ▶Weekly flights completed |
| **Ice and Snow Accumulation** | ▶Accumulations of ice or snow over the pipeline.<br>▶Snowdrifts over the pipe exceeding 5 feet or significant accumulations of ice hanging on the pipeline | ROW 1.6.1 | Ground | Weekly | ALL | | ▶Weekly inspections completed |
| **Insulation and Jacketing -- Damage** | ▶Missing insulation<br>▶Missing banding or a gap in the jacketing seams<br>▶Damage such as gouges, dents or other signs of impact or contact with the insulation or pipe. | 49 CFR 195.583 ROW 1.6.1 (3) | Ground | Annually | AOP | 22311950 | ▶Annual inspection completed |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| **Low Hanging or Damaged Cable** | ▶Electrical or fiber optic cable hanging below bottom of pipe | ROW 1.5.2<br>ROW 1.6.1 (8) | Ground | Weekly | ALL | | ▶Weekly inspections completed |
| **Low Hanging or Damaged Cable** | ▶Electrical or fiber optic cable hanging below bottom of pipe<br>▶Significant fiber optic cable damage or exposed wires | ROW 1.5.2<br>ROW 1.6.1 (8) | Ground | Annually | ADP | 22311947 | ▶Annual inspection completed |
| | | | | | AOP | 22311950 | ▶Annual inspection completed |
| | | | | | AUP | 22311951 | ▶Annual inspection completed |
| **On Pad Pipeline Mechanical Inspection -- Alpine** | ▶All situations covered under full Mechanical Inspection for the off-pad piping | ROW 1.6.1 (1)<br>ROW 2.3 | Ground | Annually | ALL | 22133983 | ▶Annual inspection completed |
| **Pipeline -- Damage** | ▶Pipeline dents, scrapes or other damage | ROW 1.6.1 (3) | Ground | Annually | ADP | 22311947 | ▶Annual inspection completed |
| | | | | | AOP | 22311950 | ▶Annual inspection completed |
| | | | | | AUP | 22311951 | ▶Annual inspection completed |
| **Pipeline Movement** | ▶Confirm documentation as required by the DOT Special Permit | 49 CFR 195.424 Special Permit | IP21 | Quarterly | ALL | 22304543<br>22195883<br>22043537<br>21888032 | ▶Quarterly reviews completed |
| **Pipeline Movement** | ▶Movement off support system<br>▶Pipes in contact with each other | ROW 1.6.1 | Aerial | Weekly | ALL | 21878047 | ▶Weekly flights completed |
| **Pipeline Movement** | ▶Movement off support system<br>▶Pipes in contact with each other | ROW 1.6.1 | Ground | Weekly | ALL | | ▶Weekly inspections completed |
| | | | | Annually | ADP | 22311947 | ▶Annual inspection completed<br>▶2016: ADP touching 12" |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| | | | | | | | pipe in 4 locations.<br>► 2017: ADP touching 12" pipe in 7 locations (3 new). PMO 22341844 includes addition of felt at these locations. |
| | | | | | AOP | 22311950 | ► Annual inspection completed<br>► 2016: AOP touching 12" pipe in 1 location.<br>► 2017: AOP touching 12" pipe in 1 location. PMO 22341845 includes addition of felt at this location. |
| | | | | | AUP | 22311951 | ► Annual inspection completed |
| **Pipeline Vibration - WIV** | ► Any excessive vibration or movement | ROW 1.6.1 | Ground | Weekly | ALL | | ► Weekly inspections completed |
| | | | | Annually | ADP | 22311947 | ► Annual inspection completed |
| | | | | | AOP | 22311950 | ► Annual inspection completed |
| | | | | | AUP | 22311951 | ► Annual inspection completed |
| **Pipeline Vibration - PVD's** | ► Missing, damaged, or broken PVD's on consecutive spans (not applicable to ADP) | ROW 1.5.3<br>ROW 1.6.1 (8)<br>ROW 3.1.1 | Ground | Weekly | AOP | | ► Weekly inspections completed |
| | | | | | AUP | | ► Weekly inspections completed |
| | | | | Annually | AOP | 22311950 | ► Annual inspection completed |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| | | | | | AUP | 22311951 | ▶2016: 98 locations identified for repair. Repaired under PMO 21760606.<br>▶2017: 92 locations identified for repair. PMO 22341845 and 22341846 created for repair. |
| **Reflective Tape -- Damage** | ▶VSM reflectors missing or damaged | ROW 1.6.1 (3)<br>ROW 1.7.2 | Ground | Annually | ALL | 22311947<br>22311950<br>22311951 | ▶Annual inspection completed<br>▶2017: 52 locations identified with damaged tape |
| **Saddle Movement** | ▶Saddle movement off the support system, or are about to be<br>▶Saddles that are tilted, suspended above crossbeams, or any gaps between pipe and saddle | ROW 1.6.1 (3) | Ground | Weekly | ALL | | ▶Weekly inspections completed |
| | | | | Annually | AOP | 22311950 | ▶Annual inspection completed |
| | | | | | AUP | 22311951 | ▶Annual inspection completed |
| **Sleeve - Inspection** | ▶Inspect for integrity | ROW 1.6.1 | Ground | Annually | AOP | 21868103 | ▶Inspection completed. No problems noted. |
| **Sloping Crossbeam/Intermediate Supports** | ▶Visible sloping | ROW 1.6.1 (3) | Ground | Annually | ADP | 22311947 | ▶Annual inspection completed<br>▶2017: 17 locations with U-bolts identified for repair. PMO 22341844 created. |
| | | | | | AOP | 22311950 | ▶Annual inspection completed |
| | | | | | AUP | 22311951 | ▶Annual inspection completed |
| **Support System -- Damage** | ▶Damaged support members.<br>▶Dents, gouges or cracks | ROW 1.6.1 (3) | Ground | Weekly | ALL | | ▶Weekly inspections completed |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| | | | | Annually | ADP | 22311947 | ▶Annual inspection completed |
| | | | | | AOP | 22311950 | ▶Annual inspection completed |
| | | | | | AUP | 22311951 | ▶Annual inspection completed |
| **Tyvar Pads or Tape Wrap -- Damage** | ▶Damaged or missing Tyvar pads at U-bolt locations<br>▶Degraded tape wrap (Denso wrap) | ROW 1.6.1 (3)<br>ROW 1.7.2 | Ground | Annually | ADP | 22311947 | ▶Annual inspection completed<br>▶2017: 2 locations identified with worn tape. PMO 22341844 created for repair. |
| **VSM -- Abandoned** | ▶VSM extending above surface level that are not capped or filled.<br>▶Surface level = tundra level or top of ice level in ponds and lakes.<br>▶Tilting, settling or jacking | ROW 1.6.1 (3)<br>ROW 3.1.1 | Ground | Annually | ADP | 22311947 | ▶Annual inspection completed |
| | | | | | AOP | 22311950 | ▶Annual inspection completed |
| | | | | | AUP | 22311951 | ▶Annual inspection completed |
| VSM -- **Abandoned at river crossings** | ▶Tilting, settling, scouring or jacking at:<br>- Miluveach River VSMs 2047A/B and 20148A/B<br>- Kachemach River VSMs 1715A/B and 1631/A | ROW 1.6.1 (3)<br>ROW 3.1.1 | Ground | Annually | ALL | 22090079 | ▶Annual inspection completed. No issues identified. |
| **VSM -- Clearance** | ▶Less than 5 feet minimum height clearance at support. | ROW 1.6.1 (6)<br>ROW 2.6.1 | Ground | Annually | ADP | 22311947 | ▶Annual inspection completed |
| | | | | | AOP | 22311950 | ▶Annual inspection completed |
| | | | | | AUP | 22311951 | ▶Annual inspection completed |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| **VSM -- Tilting, Settlement, or Jacking** | ► Evidence of or visible tilting, settlement, or jacking. | ROW 1.6.1 (3)<br>ROW 3.1.1 | Ground | Annually | ADP | 22311947 | ► Annual inspection completed |
| | | | | | AOP | 22311950 | ► Annual inspection completed<br>► 2016: casing in contact with pipe at 2G road crossing and 1 piping span identified for repair – both completed in 2017<br>► 2017: 5 piping spans identified for VSM repair in 2018. |
| | | | | | AUP | 22311951 | ► Annual inspection completed<br>► 2017: Identification of insulation touching casing at RX @ CPF2. PMO 22372307 created for repair |
| **COMMUNICATIONS** | | | | | | | |
| **Communications -- Systems** | ► Systems for receiving notices from operator personnel, the public, and public authorities of abnormal or emergency conditions, and<br>► Ability to provide this information to appropriate personnel or government agencies for corrective action | 49 CFR 195.408<br>ROW 1.2.1 | IP21 | Annually | ALL | | ► Ensured communication system integrity |
| **CORROSION CONTROL** | | | | | | | |
| **Atmospheric Corrosion Inspection** | ► Assess integrity of pipeline system.<br>► Determine the extent of | 49 CFR 195.581<br>49 CFR | Visual (VT) | 3 years | ALP:ADP | | ► Entire line inspected in 2017<br>► Light surface oxide noted |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| | external corrosion. | 195.583<br>ROW 3.2.1 | | | | | ▶Action items noted for VSM 1900 @0' to VSM 18 @ 36' |
| **Atmospheric Corrosion Inspection - Blanketed or non-insulated sections of piping** | ▶Assess integrity of pipeline system.<br>▶Determine the extent of external corrosion. | 49 CFR 195.581<br>49 CFR 195.583<br>ROW 1.6.1 (4)<br>ROW 3.2.1 | Visual (VT) | 3 years | AOP (Piggable) | | ▶2017: Light surface oxide at one location |
| | | | | | AOP @ ALP1 (Un-piggable) | | ▶2017: No damage noted |
| **Atmospheric Corrosion Inspection - (CUI) Insulated, unpiggable segments** | ▶Assess integrity of pipeline system.<br>▶Determine the extent of any corrosion. | 49 CFR 195.583<br>ROW 1.6.1 (4)<br>ROW 3.2.1 | External and Tangential Radiography (TRT) Ultrasonic Testing (UT) | 3 years | AOP CPF2 (Un-piggable) | | ▶2017:2 of 2 locations VT'd with no damage reported |
| | | | | | AOP @ ALP1 (Un-piggable) | | ▶2017: No damage noted |
| | | | | | AOP 8" Un-Piggable Sales Crude to Alpine Divert: 24-20.1 | | ▶2017: results indicated 18 H wet, 3 L corr. |
| | | | | | AOP Un-Piggable AL01 to AL03 | | ▶2017: No damage noted |
| **Atmospheric Corrosion Inspection - (CUI) Insulated, unpiggable segments** | ▶Assess integrity of pipeline system.<br>▶Determine the extent of any corrosion. | ROW 1.6.1 (4)<br>ROW 3.2.1 | External and Tangential Radiography (TRT) Ultrasonic Testing (UT) | 3 years | 6" ALPSW (Un-Piggable @ CPF-2) 6"-WO-AL1041- | | ▶2017: No CUI reported |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| | | | | | B5.4: 6"-WO-AL1041-B5.4 | | |
| | | | | | 6" ALPSW @ ALP1 (Un-piggable): MCDALPS W09_33_7.1 | | ▶2016: No damage noted |
| | | | | | 8" & 12" ALPSW (Un-piggable @ CPF2) | | ▶2017: No damage reported |
| **Atmospheric Corrosion Inspection and Internal Inspection - Cased, below grade unpiggable segments** | ▶Assess integrity of pipeline system.<br>▶Determine the extent of any corrosion. | 49 CFR 195.583<br>ROW 1.6.1 (4)<br>ROW 3.2.1 | Long Range Ultrasonic (LRUT) | 3 years | RX @ CPF-2 Alpine VSM 19 | | ▶2015: No Anomalies |
| | | | | | RX@CPF-2 Alpine VSM F2-20 | | ▶2016: No Anomalies |
| **Atmospheric Corrosion Inspection and Internal Inspection - Cased, below grade** | ▶Assess integrity of pipeline system.<br>▶Determine the extent of any corrosion. | ROW 1.6.1 (4)<br>ROW 3.2.1 | Long Range Ultrasonic (LRUT) | 3 years | AUP: RX @ CPF-2 VSM F2-20 | | ▶2015: LRUT inconclusive, circuit excavated, WCD 28% internal by UT |
| | | | | | AUP: RX@CPF-2 VSM F2-109-01 | | ▶2015: LRUT inconclusive, circuit excavated, WCD 24% internal by UT |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| **unpiggable segments** | | | | | | | |
| **Atmospheric Corrosion Inspection and Internal Inspection - Cased, below grade unpiggable segments** | ▶Assess integrity of pipeline system.<br>▶Determine the extent of external corrosion. | 49 CFR 195.581<br>49 CFR 195.583<br>ROW 3.2.1 | Long Range Ultrasonic (LRUT) | 3 years | ADP:<br>RX-ALP-01<br>RX-ALP-02<br>RX-SW-01<br>RX-SW-02<br>RX-SW-03<br>RX@CPF-2<br>ALPINE | | ▶2017: Corrosion product identified. Project initiated to replace road crossing pipe with coated pipe. |
| **Corrosion Rate Monitoring -- Locations with Known Internal Damage** | ▶Assess integrity of pipeline system.<br>▶Determine the extent of any corrosion. | 49 CFR 195.452<br>ROW 1.6.1 (4)<br>ROW 3.2.1 | Ground | Quarterly | AOP | | ▶2017 each quarter:<br>PSPW007 10%<br>PSPW007 13%<br>PSPW007 10%<br>PSPW010 17% |
| **Coupons** | ▶Determine the effectiveness of inhibitors.<br>▶Determine the extent of any corrosion. | 49 CFR 195.579 (a)<br>49 CFR 195.579 (b)(3)<br>ROW 1.6.1 (4)<br>ROW 3.2.1 | Ground | 6 months | ADP @ Alpine | | ▶2016: A, A Grade<br>▶2017: A, A Grade |
| | | | | | ADP @ CPF2 | | ▶2016: A, A Grade<br>▶2017: A, A Grade |
| | | | | | AOP @ Alpine | | ▶2016: A, A Grade<br>▶2017: A, A Grade |
| | | | | | AOP @ CPF2 | | ▶2016: A, A Grade<br>▶2017: A, A Grade |
| | | ROW 1.6.1 (4)<br>ROW 3.2.1 | Ground | 6 months | AUP @ Alpine | | ▶2016: C, A Grade<br>▶2017: D, A Grade |
| | | | | | AUP @ CPF2 | | ▶2016: F, A Grade<br>▶2017: F, A Grade |
| **Directional Change Inspection** | ▶Assess integrity of pipeline system.<br>▶Determine the extent of any | 49 CFR 195.583<br>49 CFR | Ground | 5 years | ALP:ADP | | ▶2014: Inspected 50 direction changes. No damage found. |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| | corrosion<br>▶Detect corrosion and mechanical wear associated with u-bolt and pipeline movement | 195.452(j)(3)<br>ROW 1.6.1(4)<br>ROW 3.2.1 | | | | | |
| **In-Line Inspection - Geometry (IMU) Pig** | ▶Assess integrity of pipeline system.<br>▶Determine the extent of any corrosion. | 49 CFR 195.452 (j)(5)(i)<br>ROW 1.6.1 (4)<br>ROW 3.2.1 | IMU | 4 years | AOP | | ▶2015: No imminent threats |
| | | | | | AUP | | ▶2015: No imminent threats |
| **In-Line Inspection - Smart Pigging - Includes Atmospheric Corrosion Inspection of insulated sections of piggable piping** | ▶Assess integrity of pipeline system.<br>▶Determine the extent of internal and external corrosion. | 49 CFR 195.452 (j)(5)(i)<br>49 CFR 195.583<br>ROW 1.6.1 (4)<br>ROW 3.2.1 | MFL | 2 years | AOP | | ▶2017: No imminent threats. No follow-up actions identified to date. |
| | | | | | AUP | | ▶2016: 3 imminent threats reported |
| **In-Line Inspection Follow-up** | ▶Potential pipeline system integrity issues. | ROW 1.6.1 (4)<br>ROW 3.2.1 | Ground | Conditional | AUP | | ▶ 2016 ILI: 45 of 45 internal inspection locations completed. Worst case damage is 67%<br>▶ 2016 ILI: 4 of 4 external inspection locations complete. Worst case damage is 27%. |
| **Internal Inspection - Elbows** | ▶Assess integrity of pipeline system.<br>▶Determine the extent of any corrosion and/or erosion. | 49 CFR 195.452<br>ROW 1.6.1 (4)<br>ROW 3.2.1 | Radiographic Testing (RT) | Annually | AOP | | ▶2016: No damage detected<br>▶2017: Worst-case damage of 10% wall loss by RT |
| | | | Radiographic Testing | | ADP | | ▶2016: No damage detected<br>▶2017: No damage detected |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| | | | (RT)<br>Ultrasonic Testing (UT) | | | | |
| | | ROW 1.6.1 (4)<br>ROW 3.2.1 | Radiographic Testing (RT) | 3 years | AUP | | ▶2014: Worst-case damage found by RT was 19% and 15% by UT.<br>▶2017: Worst-case damage of 20% wall loss by RT |
| **Internal Inspection - Unpiggable Segments** | ▶Assess integrity of pipeline system.<br>▶Determine the extent of any corrosion<br>▶Detect solids build up | 49 CFR 195.452 (j)(3)<br>ROW 1.6.1 (4)<br>ROW 3.2.1 | External and Tangential Radiography (TRT)<br>Ultrasonic Testing (UT) | 3 years | AOP<br>28 Circuits | | ▶2016: Worst-case damage of 33% wall loss by RT<br>▶2017: Worst-case damage of 36% wall loss by RT |
| | | | Radiographic Testing (RT)<br>Ultrasonic Testing (UT) | 3 years | ADP<br>5 Circuits | | ▶2016: A Grade<br>▶2017: Worst-case damage of 15% wall loss by RT |
| | | ROW 1.6.1 (4)<br>ROW 3.2.1 | Manual Tangential Radiography (RT)<br>Ultrasonic Testing (UT) | 3 years | AUP<br>9 Circuits | | ▶2016: D Grade<br>▶2017: Worst-case damage of 38% wall loss by RT |
| **Pressure Test** | ▶Assess integrity of pipeline system. | 49 CFR 195.302<br>49 CFR 195.452 (j)(3) | Ground | 5 years | ADP | | ▶2013: Test completed, no issues |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| | | ROW 1.6.1 (4) | | | | | |
| **ENVIRONMENTAL** | | | | | | | |
| **Endangered or Threatened Species - - Presence** | ►Presence of bird nests on or near pipeline ROW prior to activity<br>►ROW access closed each year June 1 - Aug 1 and Letter of non-Objection<br>required for access. | 49 CFR 195.6<br>ROW 1.6.1 (7)<br>ROW 2.5.3 | Ground | Conditional | ALL | | ►The 2015 study confirmed that the survey area is not commonly used by Spectacled Eiders due to a lack of suitable habitat.<br>►No Spectacled Eiders were seen within 400 m of the pipeline. |
| **Fire or Fire Hazard** | ►Any fire or fire hazard | 49 CFR 195.50 (b)<br>ROW 1.6.1<br>ROW 2.11.1 | Aerial | Weekly | ALL | 21878047 | ►Weekly flights completed |
| **Fire or Fire Hazard** | ►Any fire or fire hazard | 49 CFR 195.50 (b)<br>ROW 1.6.1<br>ROW 2.11.1 | Ground | Weekly | ALL | | ►Weekly inspections completed |
| **Fish - - Passage** | ►Blockage of fish passages<br>►All improperly screened water intake structures | ROW 1.6.1(6)<br>ROW 2.4.1 - 2.4.4 | Ground - Site Specific | Conditional | ALL | | ►No incidents of fish passage constraints |
| **Leaks or Spills** | ►Any leak or spill | 49 CFR 195.50 (b)<br>18 AAC 75.425 (e)(2)(e)<br>18 AAC 75.055<br>ROW 1.6.1<br>ROW 2.11.1 | Aerial | Weekly | ALL | 21878047 | ►See Table F-1 Discharge Summary |
| | | | Ground | Weekly | ALL | | ►See Table F-1 Discharge Summary |
| | | | Ground | Annually | ADP | 22311947 | ►See Table F-1 Discharge Summary |
| | | | | | AOP | 22311950 | ►See Table F-1 Discharge Summary |
| | | ROW 1.6.1<br>ROW 2.11.1 | Ground | Annually | AUP | 22311951 | ►See Table F-1 Discharge Summary |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| | | 49 CFR 195.50(b)<br>18 AAC 75.055<br>ROW 1.6.1<br>ROW 2.11.1 | Leak Detection System/IP21 | Continuously | ALL | | ►See Table F-1 Discharge Summary |
| **Vegetation Rehabilitation Sites** | ►Rehabilitation site results<br>►Detect need for additional treatment | ROW 1.6.1 (5)<br>ROW 2.10.1 | Ground - Site Specific | Conditional | ALL | | ►2017: tundra rehabilitation beneath AOP near Power Pole 10S near DS2S. Washout due to an adjacent river flooding during breakup. Backfilled and seeded. |
| **Vegetation Damage** | ►Dead or dying vegetation<br>►Tundra damage | ROW 1.6 (5)<br>ROW 2.11.1 | Ground - Site Specific | Conditional | ALL | | ►No damage identified |
| **Wildlife -- Caribou, Muskoxen, Grizzly Bears, Wolverines, Gray Wolf, etc.** | ►Blockage of wildlife movement | 49 CFR 195.6<br>ROW 1.6.1 (6)<br>ROW 2.6.1 | Aerial | Annually | ALL | 22082573 | ►Report Completed<br>►Results indicate no negative impacts to migration of caribou resulting from the DOT<br>pipelines being a physical barrier.<br>►No additional mitigation is necessary beyond elevated pipeline design |
| **HDD RIVER CROSSING** | | | | | | | |
| **Average Temperature** | ►Confirm 72-hour average temperatures<br>►Gauge thaw-bulb growth | ROW 1.6.1 (1)<br>ROW 3.1.1 | IP21 | Continuously | ALL | | ►Monitored via system; no issues |
| **HDDE Sandbag Cleanup Fall** | ►Inspect 2001 sandbag installation in Fall; remove debris as needed. | ROW 1.6.1 (1) | Ground | Annually | ALL | | ►Newly created PM after last SPCS inspection<br>►First inspection to occur June 2018 |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| **HDDE Sandbag Cleanup Spring** | ►Inspect 2001 sandbag installation in Spring; remove debris as needed. | ROW 1.6.1 (1) | Ground | Annually | ALL | | ►Newly created PM after last SPCS inspection<br>►First inspection to occur August 2018 |
| **Inertial Navigation Survey** | ►Evaluate pipeline stress and strain, and determine the extent of thaw settlement using in-line inspection results | ROW 1.6.1 (1)<br>ROW 3.1.1 | Pigging | 4 years | AOP | | ►ILI with IMU tool completed 5/20/15<br>►Current maximum bending strain is 0.101% (0.42% allowable). |
| **Pipeline Under Navigable Waters** | ►Perform river depth inspection<br>►Confirm crossing condition | 49 CFR 195.412 (b) | Ground | 5 years | ALL | 20447764 | ►No issues noted during 2014 inspection. |
| **Thermister Strings** | ►Confirm proper functioning<br>►Gauge thaw-bulb growth<br>►Inspections in mid-August to mid-September | ROW 1.6.1 (1)<br>ROW 3.1.1 | Ground | Annually | ALL | 22267807 | ►2016: T-09 and T12 were not readable<br>►2017: T-09 thermistor repaired PMO 22097727. T-12 does not read, but is not required. No additional issues identified. |
| **Thermosyphons** | ►Confirm proper functioning | ROW 1.6.1 (1)<br>ROW 3.1.1 | Aerial | Annually | ALL | 22338522 | ►FLIR readings indicate all are functioning |
| **INFRASTRUCTURE/EQUIPMENT** | | | | | | | |
| **Modules/Buildings -- Alpine and CPF-2 Damage** | ►Any damage to modules or supporting structure<br>►Leaks around modules or buildings | ROW 1.6.1 (1)<br>ROW 2.3 | Ground | Annually | ALL | 22133983 | ►Annual inspection completed |
| **Modules/Buildings -- HDD Damage** | ►Any damage to modules or supporting structure<br>►Leaks around modules or buildings<br>►Damage to communication sites or rectifier sites | ROW 1.6.1 (2)<br>ROW 2.11.1 | Aerial | Weekly | ALL | 21878047 | ►Weekly flights completed |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| **Modules/Buildings -- HDD Damage** | ▶Any damage to modules, supporting structure or fuel storage<br>▶Leaks around modules, buildings or fuel storage<br>▶Damage to communication sites or rectifier sites | ROW 1.6.1 (2)<br>ROW 2.11.1 | Ground | Annually | ALL | 22267807 | ▶Annual inspection completed |
| **RIGHT-OF-WAY** | | | | | | | |
| **Erosion of Gravel Pads -- ACF-1** | ▶Erosion of gravel pads including sloughing of slopes and gravel deposits on tundra, washed out areas, gullies or crevasses | ROW 1.6.1 (1)<br>ROW 2.3 | Ground | Annually | ALL | 22107321 | ▶Annual inspection completed |
| **Erosion of Gravel Pads -- CPF-2** | ▶Erosion of gravel pads including sloughing of slopes and gravel deposits on tundra, washed out areas, gullies or crevasses | ROW 1.6.1 (1)<br>ROW 2.3 | Ground | Annually | ALL | 22133983 | ▶Annual inspection completed |
| **Erosion of Gravel Pads -- HDD** | ▶Foundation settlement or jacking<br>▶Gravel pad erosion or subsidence | ROW 1.6.1 (1)<br>ROW 2.3 | Ground | Annually | ALL | 22090079 | ▶Annual inspection completed |
| **Gravel Pad Erosion** | ▶Erosion of the gravel pads including sloughing of slopes and gravel deposits on tundra, washed out areas, gullies or crevasses. | ROW 1.6.1 (1)<br>ROW 2.3 | Ground | Weekly | ALL | | ▶Weekly inspections completed |
| **Materials Storage** | ▶Inventory machinery, equipment, tools, materials and structures stored within the ROW's.<br>▶Inspect for waste or hazardous materials located in ROW's. | ROW 1.13 | Ground | Annually | ALL | 22301591 | ▶Ensured approved storage. |
| **Right-of-Way** | ▶Situations that may endanger health, safety, environment or the | 49 CFR 195.412 | Aerial | Weekly | ALL | 21878047 | ▶Weekly flights completed |
| | | | Ground | Weekly | ALL | | ▶Weekly inspections |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| | integrity of the pipeline system. | ROW 1.6.1 | | | | | completed |
| | ► Condition of the ROW | ROW 1.6.1 | Ground | Annually | ADP | 22311947 | ► Annual walk-down completed |
| | | | | | AOP | 22311950 | ► Annual walk-down completed |
| | | | | | AUP | 22311951 | ► Annual walk-down completed |
| **Signs and Markers** | ► Damaged or missing signs or markers | 49 CFR 195.410 (c) 49 CFR 195.434 ROW 1.6.1 (8) | Ground | Annually | ADP | 22311947 | ► Annual walk-down completed |
| | | | | | AOP | 22311950 | ► 2016: Missing/ damaged signs identified. Repaired under PMO 21237290 ► 2017: Annual walk-down completed. |
| | | ROW 1.6.1 (8) | Ground | Annually | AUP | 22311951 | ► Annual walk-down completed |
| **Survey Monuments** | ► Damaged monuments or accessories (top caps, rebar or other bar) | ROW 1.6.1 ROW 1.8.1 | Ground | Annually | ADP | 22311947 | ► 2016: Two monuments needing repair. Repaired under PMO 21925108 ► 2017: Inspection completed. ► Monuments returned to required position and condition |
| | | | | | AOP | 22311950 | ► 2017: Inspection completed ► Monuments returned to required position and condition |
| | | | | | AUP | 22311951 | ► 2017: Inspection completed ► Monuments returned to required position and condition |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| **Unauthorized Activities** | ►Maintenance or construction activities on or near the pipeline unknown to the Pipeline Controller.<br>►Unusual activity near the pipeline - vehicle accident, hunting, etc. | ROW 1.6.1 (7,8) | Ground | Weekly | ALL | | ►Weekly inspections completed |
| **Unauthorized Activities** | ►Maintenance or construction activities on or near the pipeline unknown to the Pipeline Controller.<br>►Unusual activity near the pipeline - vehicle accident, hunting, etc. | ROW 1.6.1 (7,8) | Aerial | Weekly | ALL | 21878047 | ►Weekly flights completed |
| **RIVER & FLOODPLAIN CROSSINGS** | | | | | | | |
| **Bank Erosion** | ►Evidence of erosion that could threaten pipeline system | ROW 1.6.1<br>ROW 2.3 | Aerial | Weekly | ALL | 21878047 | ►Weekly flights completed |
| **Bank Erosion**<br>**► Colville, Miluveach and Kachemach Rivers - -Erosion** | ►Bank erosion causing increased water turbidity<br>►Thermal erosion causing the formation of additional open water areas<br>►Banks caving near pipe centerline, where a channel migrates towards the riser<br>►VSMs that are within 15-feet of a main channel bank<br>►Bank has migrated 50-feet from as-built bank location<br>►Evidence of scour | ROW 1.6.1 (1)<br>ROW 2.3<br>ROW 3.1.1 | Ground | Annually | ALL | 22090079 | ►Inspection and report completed no issues noted<br>►Colville east side average erosion rate:<br>2016: 0.1 ft/yr<br>2017: 0.2 ft/yr<br>2017: Report concluded that the damaged thermosyphons are not contributing to bank erosion.<br>►Colville west side average erosion rate:<br>2016: 0.2 ft/yr<br>2017: 0.1 ft/yr<br>► Kachemach east side |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| | | | | | | | average erosion rate:<br>2017: 0.3 ft/yr<br>► Kachemach west side average erosion rate:<br>2017: 0.2 ft/yr<br>► Miluveach east side average erosion rate:<br>2017: 0.1 ft/yr<br>► Miluveach west side average erosion rate:<br>2017: 0.0 ft/yr<br>► No excessive scour observed |
| **Bank Migration Survey- - Colville River** | ► Measure distance from the top of the bank to the permanent baseline running parallel to each bank of the Colville River (East Channel) Pipeline Crossing<br>► Bank Migration reaching 50 percent of the design setback | ROW 1.6.1<br>ROW 2.3.2 | Ground | Annually | ALL | 22259977 | ► Measurements taken<br>► HDD West control point migration:<br>2016: 11.4% of setback<br>2017: 11.4% of setback<br>► HDD East control point migration:<br>2016: 15.7% of setback<br>2017: 15.7% of setback<br>► No action required |
| **Bank Migration Survey- - Kachemach Rivers** | ► Measure distance from the top of the bank to the permanent baseline running parallel to each bank of the Colville River (East Channel) Pipeline Crossing | ROW 1.6.1<br>ROW 2.3.2 | Ground | 5 years | ALL | 22161343 | ► Measurements taken<br>► West control point migration:<br>2017: 0.1% of setback<br>► East control point migration:<br>2017: 0.1% of setback<br>► No action required |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| **Bank Migration Survey- - Miluveach** | ►Measure distance from the top of the bank to the permanent baseline running parallel to each bank of the Colville River (East Channel) Pipeline Crossing | ROW 1.6.1<br>ROW 2.3.2 | Ground | 5 years | ALL | 22161344 | ►Measurements taken<br>►West control point migration:<br>2017: 3.5% of setback<br>►East control point migration:<br>2017: 0.0% of setback<br>►No action required |
| **Channel Change** | ►Change in the river channel flow at river crossings.<br>►New river channels which could affect pipelines<br>►Channel changes where water cannot be diverted and there is: (1) Concentrated Longitudinally flow on or along the pipeline centerline, (2) Gullying threatening the below grade pipe | ROW 1.6.1 (1)<br>ROW 2.3 | Ground | Annually | ALL | 22090079 | ►Channel morphology and flow direction within the channels remains largely unchanged. |
| **Channel Obstruction** | ►Obstructions that threaten to cause erosion or flooding of pipeline facilities.<br>►Ice dams at pipeline crossings | ROW 1.6.1 (1)<br>ROW 2.3 | Aerial | Weekly | ALL | | ►Weekly flights completed |
| | | | Ground | Annually | ALL | 22090079 | ►No obstructions noted. |
| **Depressions, Ponding, Humps or Swales** | ►Depressions occurring longitudinally over pipe axis, are deeper than 1-foot and are more than 100-feet long<br>►Ponding that extends over the pipe axis, deeper than 1-foot, and more than 100-feet long<br>►Pressure ridges developing parallel to the pipe axis and exceeding 1-foot in height and 60-feet in length | ROW 1.6.1 (1)<br>ROW 2.3 | Ground | Annually | ALL | 22090079 | ►None observed. |

| DESCRIPTION QUANTITY/ LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | METHOD | FREQUENCY | PIPELINE | PMO | RESULTS |
|---|---|---|---|---|---|---|---|
| **Flooding** | ►Evidence of flooding that could threaten a facility or pipeline.<br>►Conditions which erode the banks. | ROW 1.6.1 (1)<br>ROW 2.3 | Aerial | Weekly | ALL | 21878047 | ►Weekly flights completed |
| | | | Ground | Annually | ALL | 22090079 | ►No evidence of flooding or new river channels noted. |
| | | | | Weekly | ALL | | ►Weekly inspections completed |
| **Ground Cracking** | ►Cracks within 10-feet of pipeline centerline having one of the following characteristics:<br>►At least 10-feet long with vertical displacement exceeding 6-inches<br>►Wider than 2-inches, parallel to the pipe axis, and longer than 60-feet | ROW 1.6.1 (1,3) | Ground | Annually | ALL | 22090079 | ►None observed. |

# N. ABBREVIATIONS AND ACRONYMS

*ALPINE OIL PIPELINE* *ADL 415701*
*ALPINE UTILITY PIPELINE* *ADL 415857*
*ALPINE DIESEL PIPELINE* *ADL 415932*

ConocoPhillips

# ABBREVIATIONS AND ACRONYMS

## A

| | |
|---|---|
| AAC | Alaska Administrative Code |
| ACPF | Alpine Central Processing Facility |
| ACS | Alaska Clean Seas |
| ADEC | Alaska Department of Environmental Conservation |
| ADL | Alaska Division of Lands |
| ADP | Alpine Diesel Pipeline |
| ADNR | Alaska Department of Natural Resources |
| AFD | Authorization for Development |
| AFE | Authorization for Expenditure |
| AHF | Arctic Heating Fuel |
| AOP | Alpine Oil Pipeline |
| APC | Alpine Pipeline Company |
| API | American Petroleum Institute |
| APL | Alpine Crude Oil Pipeline |
| APSC | Alyeska Pipeline Service Company |
| ARM | Annual Routine Maintenance |
| ASH | Alaska Safety Handbook |
| ASRC | Arctic Slope Regional Corporation |
| ASTM | American Society for Testing and Materials |
| ATC | Alpine Transportation Company |
| AUP | Alpine Utility Pipeline |

## B

| | |
|---|---|
| BAT | Best Available Technology |
| bbl | barrels |
| BEAR | Behavior Eliminates All Risk |
| bpd | barrels per day |
| BPTA | BP Transportation Alaska |
| BPXA | BP Exploration Alaska |

## C

| | |
|---|---|
| CD | Colville Development |
| CFR | Code of Federal Regulations |
| CP | cathodic protection |
| CPAI | ConocoPhillips Alaska, Inc. |
| CPC | ConocoPhillips Company |
| CPF1 | Central Processing Facility 1 |
| CPF2 | Central Processing Facility 2 |
| CRU | Colville River Unit |

## D

| | |
|---|---|
| DOT | Department of Transportation |
| DS | Drill Site |

## E

| | |
|---|---|
| EMDC | ExxonMobil Development Corporation |
| EPA | Environmental Protection Agency |
| EPDDRM | Engineering Projects Data and Documents Requirements Manual |
| ESD | Emergency Shut Down |
| EIP | Energy Isolation Procedure |

## F

| | |
|---|---|
| FBE | fusion bonded epoxy |
| FERC | Federal Energy Regulatory Commission |
| FLIR | forward-looking infrared |

## G

| | |
|---|---|
| GIS | Geographic Information System |
| gpd | gallons per day |
| GIMP | Gas Integrity Management Program |

## H

| | |
|---|---|
| HAZOP | hazards and operability |
| HCA | high consequence area |
| HDD | horizontal directional-drilled |
| HEST | Health, Environmental, Safety, and Training |

# ABBREVIATIONS AND ACRONYMS

| | |
|---|---|
| HSE | Health, Safety, and Environmental |
| HSEMS | Health, Safety, and Environmental Management System Standard |
| HSM | horizontal support member |

## I

| | |
|---|---|
| ILI | in-line inspection |
| IM | Integrity Management |
| IMP | Integrity Management Program |
| ISO | International Organization for Standards |

## L

| | |
|---|---|
| LNO | Letter of Non-Objection |

## K

| | |
|---|---|
| KCC | Kuparuk Construction Complex |
| KIC | Kuparuk Industrial Center |
| KOC | Kuparuk Operations Center |
| KPE | Kuparuk Pipeline Extension |
| KPL | Kuparuk Pipeline |
| KRU | Kuparuk River Unit |
| KTC | Kuparuk Transportation Company |

## M

| | |
|---|---|
| MOC | Management of Change |
| MOP | maximum operating pressure |
| MOV | motor operated valve |
| MT | magnetic particle testing |

## N

| | |
|---|---|
| NOA | Notice of Amendment |
| NNGP | Nuiqsut Natural Gas Pipeline |
| NPMS | National Pipeline Mapping System |
| NSB | North Slope Borough |
| NSTC | North Slope Training Cooperative |
| NTSB | National Transportation Safety Board |

## O

| | |
|---|---|
| OCMS | Operations Compliance Management System |
| ODPCP | Oil Discharge Prevention and Contingency Plan |
| OPS | Office of Pipeline Safety |
| OQ | Operator Qualification |
| OSHA | Occupational Safety and Health Association |

## P

| | |
|---|---|
| PAP | Public Awareness Program |
| PCV | pressure control valve |
| PHA | Process Hazards Analysis |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PMO | plant maintenance order |
| PO | produced oil |
| PS1 | Pump Station 1 |
| PSH | pressure switch, high |
| psi | pounds per square inch |
| psig | pounds per square inch gauge |
| PSM | Process Safety Management |
| PSV | pressure safety valve |
| PVD | pipeline vibration dampener |

## Q

| | |
|---|---|
| QA | Quality Assurance |
| QC | Quality Control |
| QMS | Quality Management System |

## R

| | |
|---|---|
| RCA | Regulatory Commission of Alaska |

| | |
|---|---|
| ROV | remotely operated valve(s) |
| ROW | Right-of-Way / Rights-of-Way |
| RT | radiographic testing |

## S

| | |
|---|---|
| SCADA | supervisory control and data acquisition |
| SimOps | Simultaneous Operations |
| SIS | safety instrumented system |
| SOP | standard operating procedure |
| SPCS | State Pipeline Coordinator's Section |
| STD | standard |
| SMYS | specified minimum yield strength |

## T

| | |
|---|---|
| TAPS | Trans-Alaska Pipeline System |

## U

| | |
|---|---|
| USC | United States Code |
| UT | ultrasonic testing |

## V

| | |
|---|---|
| VPP | Voluntary Protection Program |
| VSM | vertical support member |

## W

| | |
|---|---|
| WINGS | Workforce Involvement Nurtures Greater Safety |

# ATTACHMENT 5

a. Quality Assurance Program

b. Design Criteria/As-builts - Information redacted; see Confidential Version

c. Surveillance and Monitoring

- Surveillance and Monitoring Change Justification
- Surveillance and Monitoring Program
- 2017 Annual Mechanical Ground Inspection Results
- Alpine Oil Pipeline In-Line Inspection Results
- Alpine Utility Pipeline In-Line Inspection Results

d. Environmental Compliance

- 2017 Alpine Pipeline Hydrology Monitoring - Information redacted; see Confidential Version
- Summary of Spectacled Eider Observations Along the Alpine Pipelines, 1993-2014

e. Geo-spatial Data - Information redacted; see Confidential Version

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a. **Quality Assurance Program**

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# QUALITY PROGRAM

Alpine Oil Pipeline ADL 415701
Alpine Utility Pipeline ADL 415857
Alpine Diesel Pipeline ADL 415932

June 2018
REVISION 3

ConocoPhillips

# CONTENTS

# 1. STATEMENT OF AUTHORITY

ConocoPhillips Company (CPC) has management responsibility for the following Leases and Grant.

| Lease / Grant | Pipeline | Lessee / Grantee |
|---|---|---|
| ADL 415701 | Alpine Oil Pipeline | ConocoPhillips Company |
| ADL 415857 | Alpine Utility Pipeline | ConocoPhillips Company |
| ADL 415932 | Alpine Diesel Pipeline | ConocoPhillips Company |

CPC representatives have the authority to act on behalf of the pipeline owners, lessees, and grantee; and appoint contractors for the performance of work on these pipelines.

CPC requires that design, construction, operation, maintenance, and termination activities be performed in accordance with this Quality Program.

This Quality Program applies to work by CPC and CPC Contractors. CPC Contractors are any organization or individual having a direct contract or agreement with CPC for the performance of work. CPC Contractors and their contractors and subcontractors will develop their own quality systems, programs or plans, which must meet the provisions of this Quality Program.

## AUTHORIZED REPRESENTATIVE[1]

/s/ Barry Romberg — July 12, 2018

Barry Romberg
Manager, Alaska Transportation
ConocoPhillips Company

Date

1 As required by Alpine Oil, Utility, and Diesel Pipeline ROW Leases/Grant, Section 30.

# 2. INTRODUCTION

## 2.1. PURPOSE

ConocoPhillips Company (CPC) is committed to conducting business in a manner that protects the safety and health of employees, its contractors, its customers, the public, and others involved in the operation of its facilities. Furthermore, it is committed to conducting business in a manner that assures public confidence and is compatible with the balanced environmental and economic needs of the communities in which it operates. These commitments require facilities to be designed, constructed, operated, and maintained to accepted standards, and in compliance with all applicable laws and regulations. To satisfy the following State of Alaska Right-of-Way Lease or Grant obligations (ROW Agreements)[2], CPC has developed this Quality Program.

- ADL 415701 Alpine Oil Pipeline
- ADL 415857 Alpine Utility Pipeline
- ADL 415932 Alpine Diesel Pipeline

This Quality Program defines the means of achieving industry leadership in environmental, health, safety and operational performance. It defines "what" is to be accomplished while also providing flexibility for contractors to develop their own quality systems, programs or plans and defines "how" this is to be accomplished. CPC will model positive "quality" related behaviors by personal example with clearly established goals and objectives, roles and responsibilities, performance measures, and by securing and assigning competent resources. This Quality Program was developed to assure ROW Agreement commitments are met and documented through planned and systematic actions and to provide evidence that pipeline owners and managing partners represented by CPC are satisfying applicable Federal, State and Local laws and regulations.

ConocoPhillips Alaska, Inc. is the primary contractor for CPC and will design, construct, operate, maintain and terminate the Alpine pipelines primarily through its contractors and subcontractors. For the purposes of this Quality Program, "contractor" means any organization or individual having a direct contract or agreement with CPC for the performance of work on the Alpine pipelines. Contractors are required to have quality systems, programs or plans that meet the provisions of this Quality Program.

This Quality Program includes a Quality Program Matrix of program elements, typical systems, programs and plans implemented to satisfy program elements, and processes and methods used to manage the requirements.

In cases of conflict between the requirements of this Quality Program and a contractor's quality system, program or plan, this Quality Program takes precedence.

## 2.2. RESPONSIBILITY

CPC assures the specified design, procurement, construction, maintenance, operation, and termination activities, including Quality Assurance and Control activities and processes, are in accordance with

[2] Alpine Oil, Utility, and Diesel Pipeline ROW Lease/Grant: Section 14, Plans and Permitting; and Stipulation 1.4, Quality Assurance

all applicable standards and specifications, including Federal, State and Local laws and regulations, and the requirements of the ROW Agreements.

CPC is responsible for overseeing requirements of this Quality Program through a quality management system. This Quality Program provides a means to accomplish the CPC mission to design, construct, operate, and maintain the Alpine pipeline systems in a safe, environmentally prudent and operationally efficient manner.

Everyone performing work is responsible for compliance with applicable procedures and for the quality of the work product. Contractors are required to develop and implement their own quality systems, programs or plans to meet the provisions of this Quality Program.

## 2.3. DEFINITIONS

### System

Where this Quality Program expectation requires "a system is in place", the "system" typically has the following characteristics in place and documented:

Scope and Purpose

- Purpose is defined.
- Breadth and depth of coverage are specified.
- Expected results are identified.

Procedures

- System process steps are identified.
- Written procedures for key system tasks are identified.

Responsible and Accountable Resources

- Responsibility for system administration is defined.
- Roles, responsibilities, and approval authorities are established.

Verification and Measurement

- Proper functioning of the system is verified.
- Processes exist to measure performance against objectives and expected results.

Feedback Mechanism

- Processes exist for follow-up and closure of findings from verification and measurement.
- Processes exist to review and improve system suitability and effectiveness.

Where this Quality Program specifies a system will be in place, the requirement can be satisfied by a single system, multiple systems, or incorporation into another system, even if associated with a different element, as deemed appropriate by the system developer. When an expectation does not specify “a system is in place”, the five basic characteristics of a system shown above are not required and the responsible contractor determines the extent and steps to be taken to comply with the expectation.

# 3. LEADERSHIP, COMMITMENT, AND INVOLVEMENT

## 3.1. PURPOSE

Successful implementation of this Quality Program requires management to provide the vision, set the expectations, and ensure the assignment of sufficient resources.

## 3.2. EXPECTATIONS

1) Management defines this Quality Program scope, priority, and pace; and ensures the availability of resources.

2) Management actively and visibly participates to ensure the successful development and implementation of this Quality Program throughout the organization.

3) Management establishes goals, objectives, and pro-active and re-active measurements for achieving and continually improving performance.

4) Management ensures systems are in place to translate expectations into procedures and practices.

5) Management ensures periodic reviews and assessments of the program and implementing processes, to enhance the organizations ability to properly manage risk and identify areas of improvement.

## 3.3. RESPONSIBILITIES

CPC established this Quality Program, which describes the responsibilities and lines of authority for the organization. CPC may delegate related work, in whole or part, to others by contract or agreement.

This section established the authority and responsibilities of persons and organizations performing quality activities that affect the pipeline systems.

The responsibilities and duties in the context of this Quality Program include the following:

### 3.3.1. Alaska Transportation Manager

The Alaska Transportation Manager:

- Ensures overall effectiveness of this Quality Program.
- Ensures periodic review of this Quality Program through routine assessment activities.
- Assures the pipeline meets the technical, quality, safety, and environmental requirements set forth in applicable Federal, State and Local laws and regulations, requirements of the ROW Agreements and this Quality Program.

- Delegates related work to others through contracts and agreements.
- Assures the principles of this Quality Program are included in these contracts and agreements where applicable.
- Approves changes to this Quality Program.

### 3.3.2. General Counsel

The General Counsel:

- Provides final interpretation of applicable Federal, State, and Local laws and regulations.

### 3.3.3. Regulatory Compliance Coordinator

The Regulatory Compliance Coordinator:

- Ensures periodic review of contractor pipeline operations and maintenance programs, plans, and procedures.
- Coordinates reviews and revisions to this Quality Program.
- Develops and implements an audit program to verify compliance with applicable laws and regulations, ROW Agreements, and this Quality Program.
- Delegates related work to others through contracts and agreements.
- Assures the principles of the Quality Program are included in these contracts and agreements where applicable.

### 3.3.4. Contractor

The Contractor:

- Develops and implements the required technical, quality, safety, and environmental systems, programs, and procedures set forth in applicable laws and regulations, ROW Agreement requirements and this Quality Program.
- Periodically reviews operations, maintenance, and quality systems, programs, and procedures.
- Initiates revision of operations, maintenance, and quality systems, programs, and procedures, to ensure proper management of risk and continuous improvement.

# 4. RISK MANAGEMENT

## 4.1. PURPOSE

Effective risk management provides identification, assessment and management of situations, which have the potential to adversely affect people, assets and the environment. Anticipation of potential incidents and evaluation of routine operations form the basis for efficient and effective responses, which can mitigate consequences. Effective evaluation of incidents provides valuable information for preventing future similar incidents.

## 4.2. EXPECTATIONS

1) A system is in place to identify potential hazards and liabilities, to assess risk, to evaluate prevention and mitigation measures, and to ensure control techniques are implemented for the ongoing management of risk for activities.

2) Potential hazards and risks to the work force, public, environment, and assets are assessed for existing operations, products, business developments, acquisitions, modifications, new projects, closures, divestments, and decommissioning.

3) Assessed risks and mitigative measures are addressed by management at a level appropriate to the nature and magnitude of the risk. Decisions are clearly documented and resulting actions implemented through local processes.

4) Risk assessments are updated at specified intervals and as changes are planned and implemented to ensure continuous improvement of hazard assessment and risk management process.

## 4.3. SYSTEMS, PROGRAMS AND PLANS

Typical systems, programs and plans include incident investigation programs, emergency response and spill prevention programs, hazard identification techniques, risk management strategies, risk assessment methodologies, surface water protection, community involvement programs, emergency preparedness, critical task analysis, upset mitigation and dispersion modeling.

# 5. PERSONNEL

## 5.1. Purpose

As the most valuable resource of a corporation, it is imperative personnel understand their roles and responsibilities; are empowered to actively participate in the improvement of the safety and environmental system; and are well trained to perform their duties in a safe, healthful and environmentally protective manner.

It is equally important people living in the communities in which the pipelines operate are informed about its operations; have an opportunity to express concerns about pipeline operations; and recognize the safety and environmental protection and improvement activities being implemented.

## 5.2. Roles and Responsibilities

### 5.2.1. Purpose

Accomplishing tasks in a safe and environmentally acceptable manner requires employees to have a thorough understanding of their specific areas of responsibility; have the authority to accomplish their task and be held accountable for fulfilling their roles.

### 5.2.2. Expectations

1) Roles and responsibilities are documented, maintained and clearly communicated.

2) Employees thoroughly understand their roles and responsibilities, are given authority to fulfill their assigned tasks and are accountable for such activities.

3) Employees fully and actively participate by implementing their assigned roles and responsibilities to achieve operational excellence and an incident free work place.

### 5.2.3. Systems, Programs and Plans

Typical systems, programs and plans include work rules, skills inventories and role statements.

## 5.3. Training

### 5.3.1. Purpose

Ensuring a healthy, safe, and environmentally sound operation in conformance with laws and regulations requires employees to be carefully selected, trained and their skills and competencies regularly assessed.

### 5.3.2. Expectations

1) A system is in place for initial, periodic and refresher training; and includes assessments of employee knowledge and skills relative to job requirements and legal and regulatory compliance and evaluation and improvement of the training given.

2) Recruitment, selection and placement processes ensure personnel are qualified, competent and fit for their assigned tasks.

3) Employees receive feedback on their performance, based on established criteria, measured against clearly defined objectives.

4) A system is in place to document the required proficiency, qualification or certifications for personnel.

5) New or transferred employees, contractors and other visiting personnel undergo appropriate site orientation and induction training covering environmental, health, and safety rules, and emergency procedures.

### 5.3.3. Systems, Programs and Plans

Typical systems, programs and plans include training modules, orientation programs, training needs analysis, technical training programs and training records systems.

## 5.4. INDUSTRIAL HYGIENE AND HEALTH

### 5.4.1. Purpose

Protecting the present and future health of the work force requires the identification, evaluation and control of potential health hazards.

### 5.4.2. Expectations

1) A system is in place to provide a comprehensive approach to manage personnel exposures in the workplace and provide for communication of those exposures to affected employees.

2) Employees are actively involved in anticipating, identifying, evaluating, controlling and communicating potential workplace health hazards.

3) Employees participate in decisions involving health and hygiene programs, safe work practices and continuous improvement processes.

4) Exposure assessment plans are completed for all job classifications and statistics are used to test the validity of exposure assessments.

5) A system exists to collect and review adverse effects reported or experienced by those operating and inspecting the pipeline system. Causes for concern are identified and actions are taken.

### 5.4.3. Systems, Programs and Plans

Typical systems, programs and plans include hazard communication, exposure assessment plans, medical surveillance programs, wellness programs, ergonomic assessments, off-the-job safety programs and personal protective equipment programs.

## 5.5. EMPLOYEE OWNERSHIP

### 5.5.1. Purpose

Ensuring a healthy, safe and environmentally sound operation in conformance with laws and regulations, requires employees support and shared ownership in systems, programs and processes.

### 5.5.2. Expectations

1) A system is in place to establish and support employee ownership.

2) Employees are committed and actively involved in the prevention and mitigation of incidents.

3) Human behavior techniques, identifying “at risk” behaviors, are used to limit potential incidents.

### 5.5.3. Systems, Programs and Plans

Typical systems, programs and plans include health, safety and environmental committees, employee involvement programs and self-audit programs.

## 5.6. EMPLOYEE RECOGNITION

### 5.6.1. Purpose

Ensuring a healthy, safe and environmentally sound operation in conformance with laws and regulations, requires behavior influence through recognition and positive reinforcement.

### 5.6.2. Expectations

1) Operational safe behavior and environmental protective practices are well defined.

2) Employees are trained in an “observer” process.

3) Observational data is actively used for problem solving.

#### 5.6.3. Systems, Programs and Plans

Typical systems, programs and plans include employee recognition or achievement programs.

### 5.7. COMMUNITY INVOLVEMENT

#### 5.7.1. Purpose

Achieving community awareness and maintaining public confidence in the integrity of operations and the commitment to health, safety and environmental performance, requires systems supporting the active transferring and sharing of information with public and government officials.

#### 5.7.2. Expectations

1) Open and proactive communications are established and maintained with employees, contractors, regulatory agencies, public organizations and communities to routinely share information regarding the health, safety and environmental aspects of our business.

2) Government and community expectations and concerns about operations and the transported products are recognized and addressed.

3) Health, safety and environmental impacts of new development on existing operations, neighbors, or local communities are openly assessed, communicated, and integrated into the business case.

4) Health, safety and environmental impacts of any divestment, change in operations, or decommissioning on existing operations, neighbors, or local community are reviewed, communicated and managed.

#### 5.7.3. Systems, Programs and Plans

Typical systems, programs and plans include community advisory panels, surveys, open houses, complaint response systems, community clean-up projects, participation in civic organizations and pro-active environmental projects.

# 6. CONTRACTOR SERVICES

## 6.1. PURPOSE

Contractors, suppliers and others who provide materials and services or operate facilities influence environmental, health, safety, and operational performance. It is essential such services be provided in accordance with applicable laws, regulations, corporate policies and business purpose.

## 6.2. EXPECTATIONS

1) A system is in place for evaluation, selection and on-going assessment of critical material and service contractors. Assessment addresses contractor performance and includes a feedback mechanism and ensures deficiency resolution.

2) Roles, responsibilities and performance criteria are defined, understood and agreed upon between CPC and the contractor, and are clearly communicated in contracts and written agreements.

3) Pre-qualification, selection and retention criteria are established for work performed by contractors and include a system for assuring their compliance.

4) Hazards and risks associated with contractor-implemented activities are identified, managed and communicated.

5) Clear deliverables and performance standards are agreed to and systems are in place to assure this Quality Program is consistently carried out.

6) Contractors have quality systems, programs or plans to meet the provisions of this Quality Program.

## 6.3. SYSTEMS, PROGRAMS AND PLANS

Typical systems, programs and plans include contractor selection criteria, training systems, audits, orientation programs, incident reporting and investigation systems and definitions of roles and responsibilities.

# 7. DESIGN AND CONSTRUCTION

## 7.1. PURPOSE

Proper engineering design and construction, including the use of accepted standards, procedures and specifications, establishes the foundation for continued safe and environmentally sound operation. New facilities and modifications to existing facilities must be designed and constructed to contain products under operating conditions (temperature and pressure) while considering the effects of corrosion, erosion, human error and process startups, shutdowns and upsets. As process conditions, technology or regulations change, engineering design and construction must address the suitability of existing equipment to prevent unplanned events.

## 7.2. EXPECTATIONS

1) A system is in place for managing design and construction activities to ensure regulatory, legal and corporate requirements are met or exceeded.

2) Practices, standards, or specifications exemplifying responsible design and construction practices are established to protect people, the environment and the facilities.

3) Operational, maintenance, and health, safety and environmental expertise are integrated early in the design process. Experience from previous projects and current operations are applied.

4) Deviation from approved design basis or criteria, standards or specification is permitted only after approval by the designated authority with the justification documented and retained. Design change documents, including those initiated by vendors and subcontractors, are controlled and tracked by the contractor performing the work.

5) Facilities are designed and constructed using technology to manage technical risk; minimize or eliminate emissions, discharges and other environmental impacts; and conserve energy.

6) Long-term operability, maintainability and eventual abandonment are incorporated into the design.

7) Quality assurance and inspection systems ensure facilities are designed and constructed in accordance with the design basis and criteria and applicable regulations, standards, and specifications.

8) Systems and procedures addressing technical integrity and accountabilities in this Quality Program are documented and well understood. Design, procurement and construction standards are formally approved by the designated technical or engineering authority. Formal design review, verification and validation studies are carried out based on risk assessment.

9) A pre-startup review is performed and documented to confirm:
   - Construction is in accordance with criteria, specifications and standards.
   - Deviations are approved by the designated technical authority and adequately documented.
   - Health, safety, environmental, emergency, operations and maintenance procedures are in place and fit-for-purpose.
   - Functional check out (FCO) was performed.
   - Process Hazard Analysis (PHA) recommendations were addressed and required actions taken.
   - The Work force is adequately trained, and the training system updated as necessary.

## 7.3. SYSTEMS, PROGRAMS AND PLANS

Typical systems, programs and plans include design and construction management, risk assessment and change management.

# 8. OPERATIONS AND MAINTENANCE

## 8.1. PURPOSE

Operation of the pipeline system within established parameters is essential to manage risk. In addition to designing and constructing facilities for continued safe and environmentally sound operations, equipment must be inspected and maintained to maximize reliability and operating integrity; risks associated with operations must be assessed and managed, and pollution prevention opportunities must be identified and implemented to capture the benefits.

## 8.2. MECHANICAL AND OPERATIONAL INTEGRITY

### 8.2.1. Purpose

A comprehensive mechanical and operational integrity program maximizes equipment reliability and operating integrity, provides a means to control risk, eliminate unplanned events and ensures safe, healthy and environmentally sound performance.

### 8.2.2. Expectations

1) Post-startup reviews are carried out for all newly installed or modified equipment to confirm construction is in accordance with design, all required verification testing is complete and acceptable, and all recommendations and deviations are approved by the designated technical authority.

2) Equipment out of service for maintenance or modification is subject to documented inspection and testing prior to use.

3) A system is in place to ensure the development, maintenance and accessibility of the procedures for operations, maintenance and equipment integrity. The system includes a change management process and a recertification process at specified intervals.

4) A work permit system is in place incorporating checks and authorizations consistent with operational risks.

5) A system is in place to ensure pipeline control devices, equipment and major components are calibrated, maintained and controlled within specified operating parameters.

6) Appropriate testing and maintenance programs, including management of temporary disarming or deactivation, are used to maintain reliability and availability of protective systems.

7) A system is in place to ensure the development, maintenance and accessibility of the documentation and drawings necessary for operations, maintenance and equipment integrity.

8) Regulatory, legal and corporate operations and maintenance requirements are met or exceeded. Operational, technical and mechanical integrity is maintained using operational, maintenance, procurement, inspection and corrosion control systems, standards, and practices.

9) Decommissioning, remediation and restoration plans, when generated, are established using risk-based studies for end-of-life equipment and facilities.

10) Procurement systems provide for product identification and traceability as applicable.

### 8.2.3. Systems, Programs and Plans

Typical systems, programs and plans include process and instrument diagrams, effluent and emission monitoring, preventive maintenance programs, mechanical integrity procedures, process flow diagrams, electrical classification drawings, work force qualification programs, management of change systems, quality control and assurance programs and risk-based inspection programs.

## 8.3. POLLUTION PREVENTION

### 8.3.1. Purpose

A comprehensive pollution prevention system, including all practices to reduce or eliminate the impact of pollutants or wastes, is essential to reduce the impact of operations on the environment.

### 8.3.2. Expectations

1) A comprehensive waste management system is implemented to ensure wastes are minimized, re-used, recycled, or disposed at approved sites.

2) Impacts associated with waste, emissions, noise and energy use are monitored, and minimized.

3) All applicable national and local pollution prevention requirements are met or exceeded.

4) All residual discharges regulatory, legal and corporate standards and requirements are met or exceeded.

5) Alternatives to existing products and processes are evaluated and implemented where cost-effective and appropriate to reduce the generation and release of pollutants.

6) Waste generation is routinely tracked and analyzed.

7) Pollution controls are tested and undergo preventative maintenance.

### 8.3.3. Systems, Programs and Plans

Typical systems, programs and plans include effective waste and emission tracking, monitoring energy utilization, effective cost accounting of waste disposal, recycling, risk assessment and process and product design review.

# 9. MANAGEMENT OF CHANGE

## 9.1. PURPOSE

Risks associated with temporary and permanent changes in organization, personnel, operations, procedures, design criteria, facilities, regulatory or permit requirements require evaluation and management to ensure potential health, safety, environmental and pipeline integrity risks remain at an acceptable level.

## 9.2. EXPECTATIONS

1) A system is in place for the management of both temporary and permanent changes to operations, procedures, practices, design criteria, or facilities.

2) The health, safety, security, environmental, technical and other impacts of temporary and permanent changes are formally assessed, managed, documented and approved.

3) The original scope and duration of temporary changes are not exceeded without review and approval.

4) Changes to legal and regulatory requirements, technical codes, and health and environmental affects are identified, tracked, and incorporated into policies, practices, procedures, documentation, training, design criteria and operations, as appropriate.

5) Effects of change on the workforce and organization, including training requirements, are assessed and managed.

## 9.3. SYSTEMS, PROGRAMS AND PLANS

Typical systems, programs and plans include change management systems, workforce studies, business process and improvement evaluations and efficiency studies.

# 10. STANDARDS AND PROCEDURES

## 10.1. Purpose

Standards and procedures should ensure risks are either eliminated where feasible or adequately managed. They must specify the means for successfully completing work assignments and complying with applicable regulations. Standards and procedures must be written, communicated, reviewed and maintained by each organization consistent with the needs of its business.

## 10.2. Expectations

1) A system is in place to ensure the development and implementation of environmental, health, safety, and operational performance standards and procedures.

2) New regulations are evaluated to determine if they are addressed in existing performance standards and procedures.

3) Training is conducted to ensure awareness and facilitate compliance.

## 10.3. Systems, Programs and Plans

Typical systems, programs and plans include work practices (e.g., hot work, confined space, electrical, evacuation, hazardous energy control), spill and release plans, material handling procedures, training, and business unit policies and procedures.

# 11. INFORMATION AND DOCUMENTATION

## 11.1. PURPOSE

Accurate pipeline system information and documentation on the pipeline system, properties of materials handled, potential health, safety and environmental hazards and regulatory requirements are necessary for safe, environmentally sound operations and maintenance of assets.

## 11.2. EXPECTATIONS

1) A system is in place to securely manage drawings, design data, and other documentation necessary for safe, environmentally sound, operations and maintenance of facilities.

2) Required documentation and information is accessible and current, and maintenance responsibilities are assigned.

3) Applicable regulations, permits, codes, standards and practices are identified and the applicable environmental, health, safety and operating requirements are documented and communicated to the workforce.

4) Pertinent records are maintained, available and retained as necessary. Obsolete documentation is identified and removed from circulation.

5) Scope and format of technical documentation will be agreed for each facility and will form part of the design input for new facilities and modifications.

6) Materials properties and potential hazards and operations risks are identified, documented, and communicated openly.

## 11.3. SYSTEMS, PROGRAMS AND PLANS

Typical systems and programs include records management, document control and drawing control.

# 12. PRODUCT STEWARDSHIP

## 12.1. Purpose

Product stewardship is necessary to develop appropriate environmental, health, safety and operational information and to encourage the appropriate use, transportation and disposal of products and a means of sharing information with customers, carriers and others.

## 12.2. Expectations

1) Assessments are conducted for changes to the hazardous liquid or seawater stream introduced into the pipeline system to identify health, safety, environmental and operational hazards and risks to the integrity of the system.[3]

2) Records of assessment, background information and conclusions are kept current and retained as appropriate.

3) Current information on health, safety, environmental and operational hazards and risks relating to the storage, handling, transport and disposal of the pipeline contents is available. Material Safety Data Sheets (MSDS), labels and other information are developed and issued to handlers and users in accordance with requirements and as information changes.

4) A system is in place to address environmental, health and safety adverse effects reported or experienced by those operating and inspecting the pipeline system. Causes for concern are identified and actions are taken.

## 12.3. Systems, Programs and Plans

Typical systems, programs and plans include product information sheets, product testing and product risk analysis.

[3] Other chemicals may be introduced or transported incidentally such as biocides, corrosion inhibitors, drag reducing agents, or by-products.

# 13. INCIDENT AND NONCONFORMANCE INVESTIGATION AND REPORTING

## 13.1. Purpose

Effective incident investigation implemented using the appropriate personnel, achieves improvement to environmental, health, safety and operational performance. Systems must identify, evaluate, eliminate and communicate potential hazards and risks. Findings must be communicated to share the learning experience and investigation recommendations must address root causes and are audited and tracked to completion.

## 13.2. Expectations

1) A system is in place for reporting, investigating, analyzing and documenting all health, safety, operational integrity, environmental incidents and near misses.

2) A working environment supporting and encouraging open dialogue about incidents, concerns and non-compliance occurrences is fostered.

3) A system is in place for the identification, control, and disposition of nonconforming items, including materials, component, activities or services found to be deficient.

4) Investigations identify root causes and contributing factors, determine actions needed to reduce the risk of related incidents, and ensure the appropriate action is taken.

5) Lessons learned from incidents and near misses are communicated across the organization and to other operating companies as applicable.

6) Systems are in place to ensure the regulatory reporting requirements are met.

## 13.3. Systems, Programs and Plans

Typical systems, programs and plans include incident investigation programs, root cause analysis process, and corrective action tracking.

# 14. EMERGENCY PREPAREDNESS AND MANAGEMENT

## 14.1. Purpose

Emergency planning and preparedness is essential to ensure effective actions are taken, protecting the workforce, public, environment and assets, in the event of an incident.

## 14.2. Expectations

1) An emergency preparedness system, including emergency response and management plans, is documented, accessible, clearly communicated and periodically exercised.

2) Equipment, facilities, and a trained work force needed for emergency response, including mutual aid providers, are identified, readily available and periodically tested.

3) Community, expectations, concerns and potential impacts are identified and addressed.

4) Work force is trained and understands emergency plans, their roles and responsibilities and the use of crisis management tools and resources.

5) Plans incorporate coordination between CPC, contractors, government agencies, media and the community (including neighboring facilities).

6) Business resumption plans are in place.

7) Drills and exercises are conducted to assess and improve emergency response and crisis management capabilities, including liaison with and involvement of external organizations.

8) Periodic updates of plans and training are used to incorporate lessons learned from previous incidents and exercises.

## 14.3. Systems, Programs and Plans

Typical systems, programs and plans include incident investigation programs, emergency response and spill prevention programs, business resumption plans, community involvement programs, emergency preparedness plans, tabletop drills, critical task analysis, upset mitigation and dispersion models.

# 15. ASSESSMENT AND IMPROVEMENT

## 15.1. PURPOSE

Effective safety and environmental systems are necessary to organize effort to protect people and assets. These efforts are continuously improved through systems, which establish measurements to monitor performance; identify and assess proposed and final regulations, and audit results against defined standards.

## 15.2. MEASUREMENTS

### 15.2.1. Purpose

Measurement is an essential aspect of implementing and continuously improving environmental, health, safety and operational performance. Systems must measure the achievement of plans; the extent of compliance with rules, regulations, permits and standards; and monitor injuries, illness and incidents.

### 15.2.2. Expectations

1) A system is in place for monitoring environmental, health, safety and operational performance, which includes tracking injury and illness, property loss, spills and releases, vehicle accidents, permit excursions, and operational upsets and incidents.

2) Key environmental indicators and behavioral data are used routinely by work groups to measure and monitor performance; and statistical incident data and survey information is used to focus attention on facets of the process most relevant to the operation.

3) Statistical tools are used to track and communicate trends; near miss reporting is widely used to identify root causes; the work force performs evaluations to establish pro-active objectives for continuous improvement in health, safety, environmental and operational excellence.

4) A continuous improvement process is used to reassess and, when appropriate, redefine current progression on health, safety, environmental and operational excellence.

### 15.2.3. Systems, Programs and Plans

Typical systems, programs and plans include accident and illness-reporting systems, property loss reporting systems, statistical programs, toxic release data, upsets, spills, fines, citations, compliance audits and reporting and tracking systems.

## 15.3. Regulatory Assessment and Advocacy

### 15.3.1. Purpose

Regulatory assessment and advocacy requires a system to monitor proposed and final regulations so that timely, cost effective alternatives to achieve compliance can be evaluated and implemented. Alliances with government policy makers, interested citizens, and business groups must be built to develop sound laws, regulations, and policies to promote the common objective of safe working conditions, environmental protection, and economic development.

### 15.3.2. Expectations

1) A system is in place to proactively identify key business issues and develop and pursue appropriate advocacy positions for environmental, health and safety legislation and regulation.

2) New legislation and regulations are evaluated and, as appropriate, implementation plans incorporated into business plans.

3) Regulatory advocacy and assessments are used to identify and plan for opportunities and alternate compliance scenarios.

4) Personnel, as appropriate for priority issues, accept leadership roles in selected initiatives.

5) Environmental, health, safety and operations plans are reviewed and updated annually.

### 15.3.3. Systems, Programs and Plans

Typical systems, programs and plans include regulation forecasts, compliance plans, trade association activities, government relations, community initiatives and pollution prevention.

## 15.4. Assessments

### 15.4.1. Purpose

Periodic assessments are essential to measure program performance, confirm program compliance and improve health, safety, environmental and operating excellence. This involves internal self-assessments and participation in external assessment. The information gained from such evaluations is used to document success and improve performance, programs, plans and processes.

### 15.4.2. Expectations

1) A system is in place to conduct self-assessment of the effectiveness of programs, processes and procedures, to determine the overall degree of effectiveness and conformance with this Quality Program.

2) Assessment and audit frequency and scope reflect the operation complexity, risk level and performance history.

3) A system is in place to ensure assessment and audit finding resolution and to promote continuous improvement.

4) Assessment process effectiveness is reviewed periodically, and findings used to make improvements.

### 15.4.3. Systems, Programs and Plans

Typical systems, programs and plans include self-audit programs, corporate reviews and assessments, third-party inspection programs, recommendation tracking systems and regulatory agency inspections.

# ATTACHMENT A

# RIGHT-OF-WAY AGREEMENT
# QUALITY PROGRAM MATRIX

***ALPINE PIPELINES***

| Pipeline Quality Program Matrix, Revision 3 | Health, Safety, and Environmental Management System Standard | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Element, Systems and Programs** | Policy & Leadership | Strategic Planning, Goals, & Objectives | Structure & Responsibility | Asset & Operations Integrity | Risk Assessment | Legal Req'mts & Operations Stds | Measuring & Monitoring | Emergency Preparedness | Communication | Programs & Procedures | Non-Conformance & Investigation | Audits | Document Control & Records | Review | Awareness, Training, & Competency |
| **PQP 1: Statement of Authority**<br>N/A | | | | | | | | | | | | | | | |
| **PQP 2: Introduction**<br>N/A | | | | | | ■ | | | | | | | | | |
| **PQP 3: Leadership, Commitment, and Involvement**<br>Quality Program, Resources, and Program Goals, Objectives, and Measurements | ■ | ■ | ■ | | | ■ | ■ | | | ■ | | ■ | | | |
| **PQP 4: Risk Management**<br>Incident Investigation, Emergency Response, Spill Prevention, Hazards Analysis, Risk Management, Surface Water Monitoring, Community Involvement, Dispersion Modeling | | | | | ■ | | | ■ | | | ■ | | | | |
| **PQP 5.2: Personnel, Roles and Responsibilities**<br>Committee Charter, Work Rules, Skills Inventories, Role Statements | | | ■ | | | | | | ■ | ■ | | | | | ■ |
| **PQP 5.3: Personnel, Training**<br>Training Modules, Orientation Programs, Training Needs Analysis, Technical Training Programs, Training Records Systems | | | | | | | | | | | | | | | ■ |
| **PQP 5.4: Personnel, Industrial Hygiene and Health**<br>Hazard Communications, Exposure Assessment, Medical Surveillance, Wellness Programs, Ergonomic Assessments, Off-the-Job Safety Programs, Personal Protective Equipment | | | | | ■ | | ■ | | ■ | ■ | ■ | | | | |
| **PQP 5.5: Personnel, Employee Ownership**<br>HSE Committees, Self-Audit Programs, Employee Involvement Programs | | | | | | | ■ | | | | | ■ | | | ■ |
| **PQP 5.6: Personnel, Employee Recognition**<br>Employee Recognition and Achievement Programs | ■ | | | | | | ■ | | | ■ | | | | | ■ |
| **PQP 5.7: Personnel, Community Involvement**<br>Community Advisory Panels, Surveys, Open Houses, Compliant Response Systems, Community Clean up Projects, Participation in Civic Organizations, Pro-active Environmental Projects | | ■ | | | ■ | ■ | ■ | | ■ | ■ | | | | | |
| **PQP 6: Contractor Services**<br>Contractor Selection, Training, Systems, Audits, Orientation Programs, Incident Investigation, Roles and Responsibilities | | | | ■ | ■ | | | | | | | ■ | | | |
| **PQP 7: Design and Construction**<br>Design and Construction Management, Risk Assessment, Change Management | | | | ■ | ■ | ■ | | | | | ■ | | ■ | ■ | |
| **PQP 8.2: Operations and Maintenance, Mechanical and Operational Integrity**<br>P&IDs, Effluent and Emission Monitoring, Preventive Maintenance Programs, Mechanical Integrity Procedures, Process Flow Diagrams, Electrical Classification Drawings, Work Force Qualification Programs, Management of Change Systems, Quality Control and Assurance Programs, Risk-based Inspection Programs | | | | ■ | | | | | | ■ | | | ■ | ■ | ■ |
| **PQP 8.3: Operations and Maintenance, Pollution Prevention**<br>Waste and Emission Tracking, Track of Energy Utilization, Effective Cost Accounting of Waste Disposal, Recycling, Risk Assessment, Process and Product Design Review | | | | ■ | | | ■ | | | ■ | ■ | ■ | | | ■ |
| **PQP 9: Management of Change**<br>Change Management Systems, Work Force Studies, Business Process and Improvement Evaluations, Efficiency Studies | | | | ■ | | ■ | ■ | | | ■ | | | ■ | ■ | ■ |
| **PQP 10: Standards and Procedures**<br>Work Practices, Spill and Release Plans, Material Handling Procedures, Training and Business Unit Policies and Procedures | | | | ■ | | ■ | | | | ■ | | ■ | ■ | ■ | ■ |
| **PQP 11: Information and Documentation**<br>Records Management, Document Control, Drawing Control | | | | ■ | ■ | ■ | | | | ■ | | | ■ | ■ | |
| **PQP 12: Product Stewardship**<br>Product Information Sheets, Product Testing, Product Risk Analysis | | | | | ■ | | | | | ■ | | | | | |
| **PQP 13: Incident and Nonconformance Investigation and Reporting**<br>Incident Investigation Programs, Root Cause Analysis, Corrective Action Tracking | | | | ■ | | ■ | ■ | | | ■ | ■ | ■ | | | ■ |
| **PQP 14: Emergency Preparedness and Management**<br>Incident Investigation Programs, Emergency Response and Spill Prevention Programs, Business Resumption Plans, Community Involvement Programs, Emergency Preparedness Plans, Tabletop Drills, Critical Task Analysis, Upset Mitigation, Dispersion Models | | | | | | | | ■ | ■ | | | | | | |
| **PQP 15.2: Assessment and Improvement, Measurements**<br>Accident/Illness Reporting, Property Loss, Statistics, Release Data, Upsets, Spills, Compliance Audits, Tracking Systems | | | | | | | ■ | | | | | | | | |
| **PQP 15.3: Assessment and Improvement, Regulatory Assessment and Advocacy**<br>Regulation Forecasts, Compliance Plans, Trade Association Activities, Government Relations, Community Initiatives, Pollution Prevention | | | | | | ■ | ■ | | | ■ | | | | | |
| **PQP 15.4: Assessment and Improvement, Assessments**<br>Self-audits, Corporate Assessments, Third Party Inspection, Regulatory Agency Inspections, Tracking Systems | | | | ■ | | | ■ | | | | | ■ | | ■ | |

# ATTACHMENT 5

a. Quality Assurance Program
b. Design Criteria/As-builts - Information redacted; see Confidential Version
c. **Surveillance and Monitoring**
   - **Surveillance and Monitoring Change Justification**
   - **Surveillance and Monitoring Program**
   - **2017 Annual Mechanical Ground Inspection Results**
   - **Alpine Oil Pipeline In-Line Inspection Results**
   - **Alpine Utility Pipeline In-Line Inspection Results**
d. Environmental Compliance
   - 2017 Alpine Pipeline Hydrology Monitoring - Information redacted; see Confidential Version
   - Summary of Spectacled Eider Observations Along the Alpine Pipelines, 1993-2014
e. Geo-spatial Data - Information redacted; see Confidential Version

# Surveillance and Monitoring Change Justification for the Inspection Frequency of the Alpine Utility Pipeline Manual Block Valves

**Pipeline:** Alpine Utility Pipeline (AUP)

**Requirement:** Mainline Valve Inspections

**Proposed Change:** Change frequency of inspection from every 6 months to every 3 years.

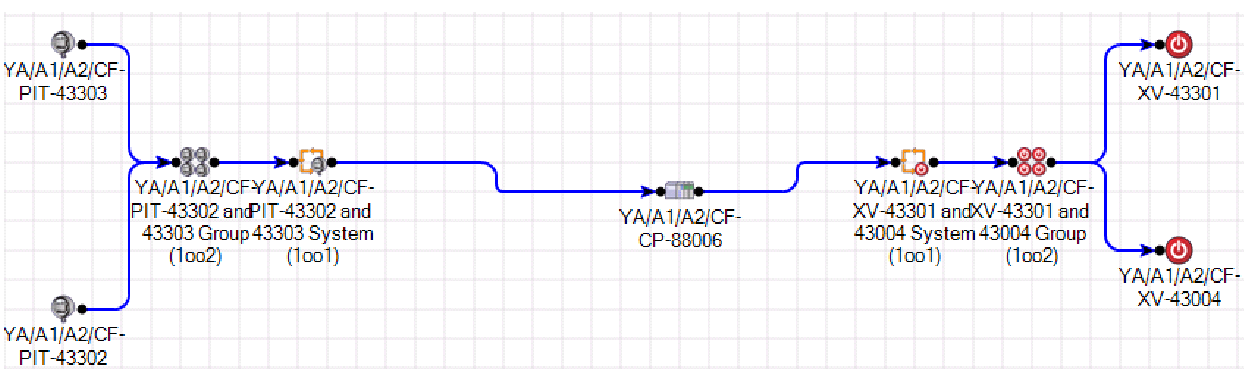
**Premise for Change:** Currently the inspection frequency for mainline valves is based on the requirements for DOT regulated pipelines as specified in 49 CFR 195.420 which requires valve inspections to be performed at intervals not exceeding 7.5 months, but at least twice each calendar year. However, the AUP is not a DOT regulated pipeline and therefore this frequency is not regulatory required. To date CPAI has maintained the valves to this frequency for simplicity of tracking, however with more advance PM tracking tools this is no longer necessary and does not result in the most effective or efficient use of inspection resources.

Testing of the AUP valves should follow the requirements as specified in the Alpine Equipment Integrity Program (AEIP), which outlines the testing requirements for Alpine equipment. The AEIP indicates the following for non-DOT regulated valves:

<u>Actuated Block Valves and Control Valves</u>

If utilized within the Process Hazards Analysis (PHA) as a Safety Instrumented Function (SIF) required for risk reduction for a hazards scenario, the maintenance frequency must be sufficient to provide the risk reduction required by the PHA scenario(s). Review of the AUP PHA scenarios which utilize SIFs involving Actuated or Control Valves to adequately mitigate risk indicate a required probability of failure upon demand (PFD) <= 0.1. The SIFs credited within these scenarios include ACF-SIF0035 and ACF-SIF037. A diagram of each SIF as well as the calculated PFDs for each is included below.

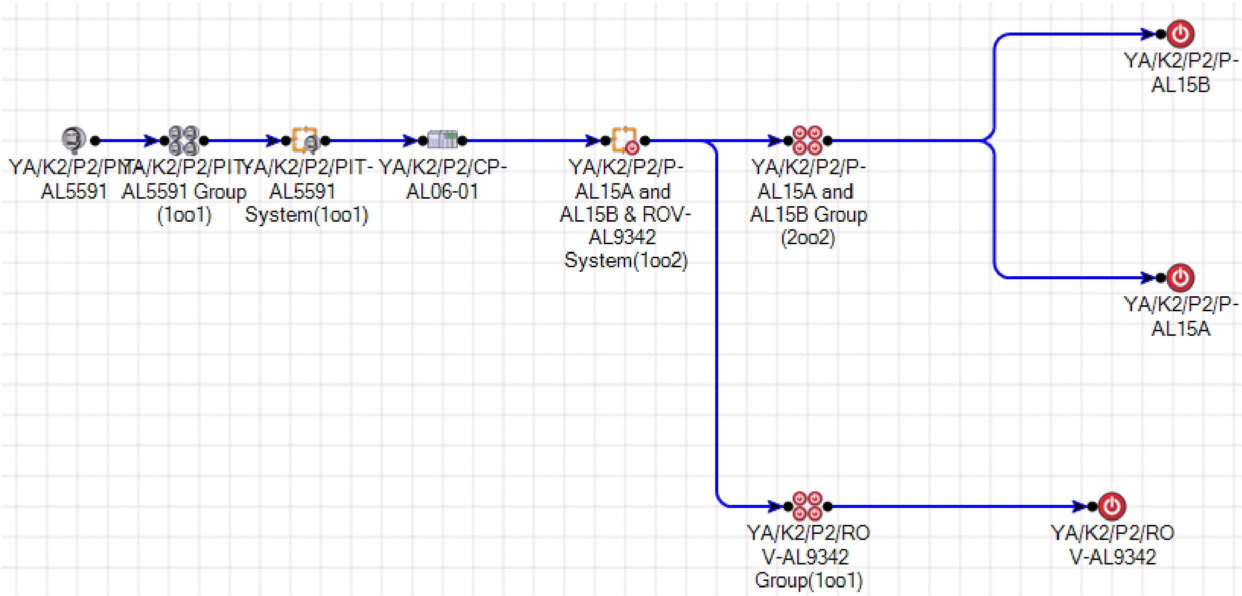
Valves XV-43301 and XV-43004 are used in ACF-SIF035:




| System Part | Component Tags | Test Frequency (Months) | Calculated PFD |
|---|---|---|---|
| Sensors | YA/A1/A2/CF-PIT-43302 and 43303 System | 36 | 2.44E-04 |
| Logic Solver | YA/A1/A2/CF-CP-88006 | 36 | 1.73E-03 |

| | | | |
|---|---|---|---|
| Final Elements | YA/A1/A2/**CF-XV-43301** and **43004** System | 36 | 5.33E-03 |
| | | Overall PFD | 7.33E-03 |

ROV-AL9342 is used in ACF-SIF037:




| System Part | Component Tags | Test Frequency (Months) | Calculated PFD |
|---|---|---|---|
| Sensor | YA/K2/P2/PIT-AL5591 System | 36 | 2.36E-03 |
| Logic Solver | YA/K2/P2/CP-AL06-01 | 36 | 1.73E-03 |
| Final Elements | YA/K2/P2/P-AL15A and AL15B & **ROV-AL9342** System | 36 | 1.72E-03 |
| | | Overall PFD | 5.8E-03 |

In each case, a testing frequency of 36 months results in a calculated PFD < 0.1 and therefore provides the risk reduction required.

Manual Block Valves

Per the AIEP, Manual Block Valves are generally not included in a scheduled inspection, test, or maintenance program other than Operator monitoring during rounds.

Manual Block Valves are not utilized within the PHA as a safety critical level of protection and therefore there is no required testing frequency. However, the mainline manual valves associated with the AUP will be maintained on the same 3-year frequency as the Automated Valves.

# SURVEILLANCE AND MONITORING PROGRAM

Alpine Oil Pipeline ADL 415701
Alpine Utility Pipeline ADL 415857
Alpine Diesel Pipeline ADL 415932

JULY 2018
EDITION 1, REVISION 2

# CONTENTS



## TABLES



## FIGURES

# ENDORSEMENT

We the undersigned endorse this *Surveillance and Monitoring Program*, Edition 1, Revision 2, for use by ConocoPhillips Alaska, Inc., Colville River Unit, the entity responsible for pipeline operations and maintenance; and ConocoPhillips Company, the entity responsible for management of the following Right-of-Way Leases and Grant.

| Lease / Grant | Pipeline | Lessee / Grantee |
|---|---|---|
| ADL 415701 | Alpine Oil Pipeline | ConocoPhillips Company |
| ADL 415857 | Alpine Utility Pipeline | ConocoPhillips Company |
| ADL 415932 | Alpine Diesel Pipeline | ConocoPhillips Company |

/s/ Misty Alexa — July 12, 2018

Misty Alexa — Date
WNS Operations Manager
ConocoPhillips Alaska, Inc.

/s/ Barry Romberg — July 12, 2018

Barry Romberg [1] — Date
Manager, Alaska Transportation
ConocoPhillips Company

1 "Authorized Representative" as required by Right-of-Way Leases and Grant, Section 30.

# 1 PURPOSE

In accordance with Section 14(c) of the Right-of-Way Leases and Grant listed in Table 1.1, this Surveillance and Monitoring Program identifies activities that:

- Assure the integrity of the pipeline system.
- Minimize any potential risk to the environment.
- Minimize any potential risk to the health and safety of employees, contractors, and the general public.

Table 1.1 Right-of-Way Leases and Grant

| Lease / Grant | Pipeline | Lessee / Grantee |
|---|---|---|
| ADL 415701 | Alpine Oil Pipeline | ConocoPhillips Company |
| ADL 415857 | Alpine Utility Pipeline | ConocoPhillips Company |
| ADL 415932 | Alpine Diesel Pipeline | ConocoPhillips Company |

This program does not govern or replace other manuals, programs, or regulatory requirements involving procedures related to the operation and maintenance of these pipelines. It is a supplement that focuses on Right-of-Way Lease and Grant requirements.

# 2 SCOPE

The scope of the Surveillance and Monitoring Program includes the detection and abatement of situations that may endanger health, safety, the environment, or pipeline system integrity. It addresses the following attributes during construction, maintenance, operation, and termination of the pipeline system:

i. Rivers, stream, and flood plain crossings

ii. Valve pads

iii. Frost heave or thaw settlement and pipeline vertical movement

iv. Corrosion

v. Restoration and rehabilitation

vi. Fish and wildlife protection

vii. Zones of restricted activity

viii. Public access and safety

# 3 REFERENCES

- Alpine Pipelines Quality Program
- Alpine Oil Pipeline Right-of-Way Lease, ADL 415701
- Alpine Utility Pipeline Right-of-Way Grant, ADL 415857
- Alpine Diesel Pipeline Right-of-Way Lease, ADL 415932
- North Slope Pipelines Operation Manual
- Alpine Crude Oil Pipeline Operation Manual
- Alpine Seawater Pipeline Operation Manual
- Alpine Arctic Heating Fuel Pipeline Operation Manual

# 4 DEFINITIONS

Surveillance is making observations, primarily qualitative, by flying, driving, or walking along the pipeline and related facilities. Surveillance is limited to direct observations, properly documenting the observations, and reporting the observations.

Monitoring is the acquisition, storage, and evaluation of quantitative data using specific instrumentation. Monitoring information is gathered and used to recognize trends, detect unknown and unexpected problems, and to plan and prioritize preventive measures or repairs.

# 5 RESPONSIBILITIES

## 5.1 ConocoPhillips Company (CPC)

### 5.1.1 MANAGER, ALASKA TRANSPORTATION[2]

The Manager, Alaska Transportation is responsible for:

- Program development, approval, implementation, and improvement.
- Ensuring compliance through audits.
- Ensuring timely resolution of noncompliant situations.

### 5.1.2 REGULATORY COMPLIANCE COORDINATOR

The Regulatory Compliance Coordinator is responsible for:

- Notifying the Manager, Alaska Transportation of noncompliant situations to ensure resolution, as appropriate.

[2] "Authorized Representative" as required by Right-of-Way Leases and Grant, Section 30.

- Facilitating program implementation, maintenance, and improvement.
- Performing internal assessments and participating in external audits to ensure the resolution of compliance issues.
- Coordinating reporting requirements.

## 5.2 ConocoPhillips Alaska, Inc. (CPAI)

### 5.2.1 CPF3 Operations Superintendent

The CPF3 Operations Superintendent is responsible for:

- Developing plans, programs, and procedures to ensure the communication and effective implementation of surveillance and monitoring requirements.
- Ensuring performance of surveillance and monitoring during construction, operations, maintenance, and termination activities.
- Implementing engineering solutions and corrective actions to address reported conditions.
- Ensuring the integration of surveillance and monitoring data into other required programs, processes, and procedures (e.g., integrity management, public awareness, corrosion control, etc.), as applicable.
- Identifying opportunities for program improvement.

### 5.2.2 Alpine Environmental Coordinator

The Alpine Environmental Coordinator is responsible for:

- Developing plans, programs, and procedures to ensure the communication and effective implementation of environmental surveillance and monitoring requirements.
- Performing environmental surveillance and monitoring activities.
- Identifying opportunities for program improvement.

### 5.2.3 Field Mechanical/Piping Engineer

The Field Mechanical/Piping Engineer is responsible for:

- Performing engineering evaluations, in accordance with applicable standards, to address surveillance and monitoring reportable conditions, as required.
- Providing engineering support, as required, to address reported conditions.

#### 5.2.4 DOT Compliance Specialist

The DOT Compliance Specialist is responsible for:

- Coordinating the implementation of engineering solutions and corrective actions to address reported conditions.
- Communicating surveillance and monitoring data to others responsible for required programs, processes, and procedures (e.g., integrity management, public awareness, corrosion control, etc.), as applicable.
- Providing quarterly and annual surveillance and monitoring updates and reports.

# 6 PROCESS

## 6.1 Surveillance

Aerial or ground-based surveillance is performed periodically to detect conditions that may:

- Affect the integrity of the pipeline system.
- Create potential health or safety hazards.
- Cause environmental harm, including adverse effects on fish and wildlife.
- Compromise compliance with applicable Right-of-Way Lease or Grant requirements.

Specific requirements, methods, and frequencies are defined in Table 6.1, Surveillance and Monitoring Matrix.

## 6.2 Monitoring

Monitoring, which includes the acquisition, storage, and evaluation of quantitative data, is performed to anticipate and detect potential:

- Pipeline system integrity issues.
- Situations that may endanger health or safety.
- Environmental hazards, including adverse effects on fish and wildlife.
- Right-of-Way Lease or Grant compliance issues.

Specific requirements, methods, and frequencies are defined in Table 6.1, Surveillance and Monitoring Matrix.

Table 6.1 Alpine Pipelines Surveillance and Monitoring Matrix

| SURVEILLANCE AND MONITORING PROGRAM | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DESCRIPTION QUANTITY/LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE ROW STIPULATION EXHIBIT A CRITERIA | ■ ■ | METHOD | | | | | | FREQUENCY QUANTITY | | | | | | |
| | | | ACTIVITY | Aerial | Ground | Leak Detect | IP21 | Pigging | Site Specific | Weekly | Monthly | Months (#) | Years (#) | Conditional | Continuous |
| **ABOVE GROUND PIPELINE** | | | | | | | | | | | | | | | | |
| **Ice and Snow Accumulation** | ►Accumulations of ice or snow over the pipelines. | ROW 1.6.1 | ■ | ■ | | | | | | ■ | | | | | |
| **Low Hanging Cable** | ►Electrical or fiber optic cable hanging below bottom of pipe | ROW 1.5.2<br>ROW 1.6.1 (8) | ■ | | ■ | | | | | ■ | | | 1 | | |
| **Anchor Movement** | ►Anchor out of level or broken welds. | ROW 1.6.1 (3)<br>ROW 3.1.1 | ■ | | ■ | | | | | | | | 1 | | |
| **VSM** -- Tilting, Settlement, or Jacking | ►Evidence of or visible tilting, settlement, or jacking.<br>►Less than 5 feet minimum height clearance at support, or 3 feet above the 200-year flood level, whichever is greater. | ROW 1.6.1(3)<br>ROW 3.1.1 | ■ | | ■ | | | | | | | | 1 | | |
| **VSM** -- Abandoned | ►VSM extending above surface level that are not capped or filled. | ROW 1.6.1(3)<br>ROW 3.1.1 | ■ | | ■ | | | | | | | | 1 | | |
| **Sloping Crossbeam/Intermediate Supports** | ►Visible sloping | ROW 1.6.1(3) | ■ | | ■ | | | | | | | | 1 | | |
| **Tilted/Suspended Saddle**<br>**Not applicable to ADP* | ►Saddles that are tilted, suspended above crossbeams, or any gaps between pipe and saddle. | ROW 1.6.1(3) | ■ | | ■ | | | | | | | | 1 | | |
| **Pipeline** -- Damage | ►Pipeline dents, scrapes or other damage | ROW 1.6.1(3) | ■ | | ■ | | | | | | | | 1 | | |
| **Support System** -- Damage | ►Damaged support members.<br>►Dents, gouges or cracks | ROW 1.6.1(3) | ■ | | ■ | | | | | ■ | | | 1 | | |
| **Component** -- Damage | ►Structural damage to clamps, saddle assemblies, crossbeams/HSM, brackets and anchor assemblies | ROW 1.6.3(3) | ■ | | ■ | | | | | | | | 1 | | |
| **Tyvar Pads and Reflective Tape** - - Damage | ►Damaged or missing Tyvar pads<br>►VSM reflectors missing or damaged | ROW 1.6.1(3)<br>ROW 1.7.2 | ■ | | ■ | | | | | | | | 1 | | |
| **Insulation, Coatings, Tyvar Pads** -- Damage | ►Shrink sleeves of FBE coating damage<br>►Significant indentations, cracks, dents, cuts, or missing foam insulation<br>►Damaged or missing tyvar pads at U-bold locations (*applies only to ADP*) | ROW 1.6.1(4) | ■ | | ■ | | | | | | | | 1 | | |
| **Pipeline Movement** | ►Movement off support system<br>►Saddle off HSM ►Pipes in contact with eachother | ROW 1.6.1 | ■ | ■ | | | | | | ■ | | | | | |
| **Pipeline Vibration - WIV** | ►Any excessive vibration or movement (amplitudes above .05") | ROW 1.6.1 | ■ | | ■ | | | | | ■ | | | 1 | | |
| **Pipeline Vibration - PVD's**<br>**Not applicable to ADP* | ►Missing, damaged, or broken PVD's on consecutive spans | ROW 1.5.3<br>ROW 1.6.1 (8)<br>ROW 3.1.1 | ■ | | ■ | | | | | ■ | | | 1 | | |
| **COMMUNICATIONS** | | | | | | | | | | | | | | | | |
| **Communications Systems** | ►Systems for receiving notices from operator personnel, the public, and public authorities of abnormal or emergency conditions and,<br>►Ability to provide this information to appropriate personnel or government agencies for corrective action | ROW 1.2.1 | ■ | | | | | | | | | | 1 | | ■ |
| **Two-Way Communications Systems** - -Telecommunication Equipment | ►Ensure systems between control room and remote locations are available and functioning properly | ROW 1.2.1 | ■ | | | | ■ | | | | | | 1 | | ■ |
| **Public Education**<br>**Operator Defined* | ►Conduct public educational and awareness programs in English and other lanuages commonly understood by a signficant number of non-English speaking populations | 49 CFR 195.440<br>ROW 1.6.1(8) | ■ | | | | | | | | | | 1 | | |

## SURVEILLANCE AND MONITORING PROGRAM

| DESCRIPTION QUANTITY/LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE ROW STIPULATION EXHIBIT A CRITERIA | ■ ■ | METHOD | | | | | | FREQUENCY QUANTITY | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ACTIVITY | Aerial | Ground | Leak Detect | IP21 | Pigging | Site Specific | Weekly | Monthly | Months (#) | Years (#) | Conditional | Continuous |
| **CORROSION CONTROL** | | | | | | | | | | | | | | | |
| **Cleaning Pigs** **Operator Defined* | ► Ensure the pipeline is free of solids, deposits, and water dropout. | ROW 1.6.1(4) ROW 3.1.1 ROW 3.2.1 | ■ | | | | | ■ | | | ■ | | | AOP | |
| | | | ■ | | | | | ■ | | 3 | | | | AUP | |
| | | | ■ | | | | | ■ | | | | 3 | | ADP | |
| **Coupons** | ► Determine the effectiveness of inhibitors. ► Determine the extent of any corrosion. | ROW 1.6.1(4) ROW 3.2.1 | ■ | | ■ | | | | | | | 6 | | | |
| **In-Line Inspection** **Not applicable to the ADP* | ► Assess integrity of pipeline system. ► Determine the extent of any corrosion. | ROW 1.6.1(4) ROW 3.2.1 | ■ | | | | | ■ | | | | | 2 | | |
| | | | | | | | | | | AOP & AUP baseline runs 2003 | | | | | |
| **In-Line Inspection Follow-up** **Not applicable to the ADP* | ► Potential pipeline system integrity issues. | ROW 1.6.1(4) ROW 3.2.1 | ■ | | ■ | | | | | | | | | ■ | |
| **Pressure Testing** **Not applicable to the AOP & AUP* | ► Assess integrity of pipeline system | ROW 1.6.1(4) | ■ | | ■ | | | | | | | | 5 | | |
| **Unpiggable Segments** | ► Assess integrity of pipeline system. ► Determine the extent of any corrosion ► Detect solids build-up | ROW 1.6.1(4) ROW 3.2.1 | ■ | | ■ | | | | | | | | 3 | | |
| **Directional Change Inspections** **Not applicable to the AOP & AUP* | ► Assess integrity of pipeline system. ► Determine the extent of any corrosion ► Detect corrosion and mehanical wear assocaited with u-bolt and pipeline movement | ROW 1.6.1(4) ROW 3.2.1 | ■ | | ■ | | | | | | | | 5 | | |
| **Corrosion Under Insulation (CUI)** **Not applicable to the ADP* | ► Assess integrity of pipeline system. ► Determine the extent of any corrosion. | ROW 1.6.1 (4) ROW 3.2.1 | ■ | | ■ | | | | | | | | 3 | ■ | |
| | | | | External and Tangential Radiography (TRT) Ultrasonic Testing (UT) | | | | | | | | | | | |
| **Elbows** -- Corrosion / Erosion | ► Assess integrity of pipeline system. ► Determine the extent of any corrosion. | ROW 1.6.1 (4) ROW 3.2.1 | ■ | | ■ | | | | | | | | 1 | ■ | |
| | | | | Radiographic Testing (RT) Ultrasonic Testing (UT) | | | | | | | | | | | |
| **Below Grade Casings** | ► Ensure casing is free of obstructions that could increase the potential for external corrosion. | ROW 1.6.1 (4) ROW 3.2.1 | ■ | | ■ | | | | | | | | 1 | | |
| | | | | | | | | | | AOP: 7 circuits KRU AUP: 6 circuits KRU ADP: 6 circuits KRU | | | | | |
| **Casing Isolation Test - -** HDD | ► Confirm proper functioning | ROW 1.6.1(4) ROW 3.1.1 ROW 3.2.1 | ■ | | | | | | | | | | 1 | | |
| **Cathodic Protection System** -- HDD | ► Rectifier Readings ► Confirm proper functioning | ROW 1.6.1(4) ROW 3.1.1 ROW 3.2.1 | ■ | | | | ■ | | | | | 2 | | | |
| | ► Confirm proper functioning ► Rectifier Readings ► System Inspection | ROW 1.6.1(4) ROW 3.1.1 ROW 3.2.1 | ■ | | ■ | | | | | | | | 1 | | |
| **ENVIRONMENTAL** | | | | | | | | | | | | | | | |
| **Leaks or Spills** | ► Any leak or spill | ROW 1.6.1 ROW 2.11.1 | ■ | | | ■ | | | | | | | | | ■ |
| | | | | ■ | ■ | | | | | ■ | | | 1 | | |
| **Fire or Fire Hazard** | ► Any fire or fire hazard | ROW 1.6.1 ROW 2.11.1 | ■ | ■ | | | | | | ■ | | | | | |
| **Vegetation Damage** | ► Dead or dying vegetation ► Tundra damage | ROW 1.6.1 (5) ROW 2.11.1 | ■ | | ■ | | | | | | | | 1 | | |
| **Vegetation Rehabilitation Sites** | ► Rehabilitation site results | ROW 1.6.1 (5) ROW 2.10.1 | ■ | | ■ | | | | ■ | | | | | ■ | |
| **Fish** | ► Blockage of fish passages ► All improperly screened water intake structures | ROW 1.6.1 (6) ROW 2.4.1 - 2.4 | ■ | | ■ | | | | ■ | | | | | ■ | |
| **Wildlife** -- Caribou, Muskoxen, Grizzly Bears, Wolverines, Gray Wolf, etc. | ► Blockage of wildlife movement | ROW 1.6.1(6) ROW 2.6.1 | ■ | ■ | | | | | | | | | 1 | | |

## SURVEILLANCE AND MONITORING PROGRAM

| DESCRIPTION QUANTITY/LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE ROW STIPULATION EXHIBIT A CRITERIA | 🟩 🟦 ACTIVITY | METHOD Aerial | Ground | Leak Detect | IP21 | Pigging | Site Specific | FREQUENCY QUANTITY Weekly | Monthly | Months (#) | Years (#) | Conditional | Continuous |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Bear Dens** - -Presence | ►Presence of bear dens on or near pipeline ROW<br>►Coordinate with ADNR-OHMP and the USF&WS for den locations | ROW 1.6.1(6)<br>ROW 2.5.2<br>ROW 2.5.3 | 🟩 | ■ | | | | | | | | | 1 | | |
| **Endangered or Threatened Species - -**Presence | ►Presence of bird nests on or near pipeline ROW<br>►ROW access closed each year June 1 - Aug 1 and Letter of non-Objection required for access. | ROW 1.6.1(7)<br>ROW 2.5.3 | 🟩 | ■ | | | | | ■ | | | | | ■ | |

### LEAK DETECTION

| DESCRIPTION QUANTITY/LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | ACTIVITY | Aerial | Ground | Leak Detect | IP21 | Pigging | Site Specific | Weekly | Monthly | Months (#) | Years (#) | Conditional | Continuous |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Leak Detection System** | ►Confirm proper functioning of instrumentation. | 18 AAC 75.055<br>ROW 1.6.1 | 🟦 | | ■ | | | | | | | | 1 | | |
| | ►Confirm proper system functioning and effectiveness. | 18 AAC 75.055<br>ROW 3.1 | 🟦 | | ■ | | | | | | | | 5 | | |

### INFRASTRUCTURE/EQUIPMENT

| DESCRIPTION QUANTITY/LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | ACTIVITY | Aerial | Ground | Leak Detect | IP21 | Pigging | Site Specific | Weekly | Monthly | Months (#) | Years (#) | Conditional | Continuous |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Modules/Buildings** | ►Any damage to modules or supporting structure<br>►Leaks around modules or buildings<br>►Debris or corrosion around building sumps ►Damage to communication sites or rectifier sites | ROW 1.6.1(1)<br>ROW 2.11.1 | 🟩 | ■ | | | | | | ■ | | | | | |
| **Foundation Movement** | ►Leaks around modules or buildings.<br>►Debris or corrosion around building sumps | ROW 1.6.1(1)<br>ROW 1.6.1(3) | 🟩 | | ■ | | | | | | | | 1 | | |
| **Breakout Tank** | ►Inspect and maintain physical integrity | ROW 1.6.1(4)<br>18 AAC 75.065 | 🟩 | | | | | | ■ | | | | 1 | | |
| | ►Monthly Inspections | | 🟩 | | | | | | ■ | | ■ | | | | |
| | ►Certified Inspection | | 🟦 | | | | | | ■ | | | | 5 | | |
| | ►Inspect for damage<br>►Confirm proper functioning | | 🟦 | | | | | | ■ | | | | 1 | | |
| | ►Overfill protection system inspect, calibrate and test | | 🟦 | | | | | | ■ | | | | 1 | | |

### RIGHT-OF-WAY

| DESCRIPTION QUANTITY/LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | ACTIVITY | Aerial | Ground | Leak Detect | IP21 | Pigging | Site Specific | Weekly | Monthly | Months (#) | Years (#) | Conditional | Continuous |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Right-of-Way** | ►Situations that may endanger health, safety, environment or the integrity of the pipeline system. ► Condition of the ROW | ROW 1.6.1<br>ROW | 🟩 | ■ | ■ | | | | | ■ | | | 1 | | |
| **Road Crossing Casing Coverage** | ►Casings have a minimum coverage depth less than 12 inches<br>►Maximum grade of the modified roadway is greater than 3%<br>►Side slopes do not match existing slopes | ROW 1.6.1 (8)<br>ROW 2.3.1.1 | 🟩 | | ■ | | | | | | | | 2 | | |
| **Erosion of Gravel Pads - -** HDD, CPF-2, ACF-1 | ►Erosion of gravel pads including sloughing of slopes and gravel deposits on tundra, washed out areas, gullies or crevaces | ROW 1.6.1 (1)<br>ROW 2.3 | 🟩 | | ■ | | | | | | | | 1 | | |
| **Signs and Markers** | ►Damaged or missing signs or markers | ROW 1.6.1(8) | 🟩 | | ■ | | | | | | | | 1 | | |
| **Survey Monuments** | ►Damaged monuments or accessories | ROW 1.6.1<br>ROW 1.8.1 | 🟩 | | ■ | | | | | | | | 1 | | |
| **Unauthorized Construction Activities** | ►Work or construction activities on or near the pipeline unknown to the Board Operator. | ROW 1.6.1 (8) | 🟩 | ■ | ■ | | | | | ■ | | | 1 | | |
| **Materials Storage** | ►Inventory machinery, equipment, tools, materials and structures stored within the ROW's.<br>►Inspect for waste or hazardous materials located in ROW's. | ROW 1.6.1<br>ROW 1.13.1-2 | 🟩 | | ■ | | | | | | | | 1 | | |

### HDD RIVER CROSSING - - THAW SETTLEMENT

| DESCRIPTION QUANTITY/LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE | ACTIVITY | Aerial | Ground | Leak Detect | IP21 | Pigging | Site Specific | Weekly | Monthly | Months (#) | Years (#) | Conditional | Continuous |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Electrical Isolation Test and End Seal Inspections** | ►Inspect for migration of moisture or liquids in casing<br>►Confirm proper functioning | ROW1.6.1(1) | 🟦 | | ■ | | | | | | | | 1 | | |
| **Thermosyphons** | ►Confirm proper functioning | ROW 1.6.1(1)<br>ROW 3.1.1 | 🟦 | | ■ | | | | | | | | 1 | | |
| **Thermister Strings** | ►Confirm proper functioning ►Gauge thaw-bulb growth ►Inspections in mid-August to mid-September | ROW 1.6.1(1)<br>ROW 3.1.1 | 🟦 | | ■ | | | | | | | | 1 | | |

## SURVEILLANCE AND MONITORING PROGRAM

| DESCRIPTION QUANTITY/LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE ROW STIPULATION EXHIBIT A CRITERIA | 🟩 🟦 ACTIVITY | METHOD Aerial | Ground | Leak Detect | IP21 | Pigging | Site Specific | FREQUENCY QUANTITY Weekly | Monthly | Months (#) | Years (#) | Conditional | Continuous |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Temperature** | ►Confirm 72-hour average temperatures<br>►Gauge thaw-bulb growth | ROW 1.6.1(1)<br>ROW 3.1.1 | 🟦 | | | | | | | | | | | | ■ |
| **Inertial Navigation Survey** | ►Evaluate pipeline stress and strain, and determine the extent of thaw settlement using in-line inspection results | ROW 1.6.1(1)<br>ROW 3.1.1 | 🟦 | | | | | | | | | | 4 | | |
| **Pipeline Under Navigable Waters** | ►Perform river depth inspection<br>►Confirm crossing condition | ROW 1.6.1(1) | 🟦 | | | | | | | | | | 5 | | |

### RIVER & FLOODPLAIN CROSSINGS

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Bank Erosion** | ►Evidence of erosion that could threaten pipeline system | ROW 1.6.1(1)<br>ROW 2.3 | 🟩 | ■ | | | | | | ■ | | | | | |
| ► Colville River - -Erosion | ►Bank erosion causing increased water turbidity<br>►Thermal erosion causing the formation of additonal open water areas<br>►Banks caving near pipe centerline, where a channel migrates towards the riser ►VSMs that are within 15-feet of a main channel bank<br>►Bank has migrated 50-feet from as-built bank location | ROW 1.6.1(1)<br>ROW 2.3<br>ROW 3.1.1 | 🟩 | | ■ | | | | | | | | 1 | | |
| ►Miluveach and Kachemach Rivers - - Erosion | ►Bank erosion causing increased water turbidity ►Thermal erosion causing the formation of additonal open water areas<br>►Banks caving near pipe centerline, where a channel migrates towards the riser ►VSMs that are within 15-feet of a main channel bank<br>►Evidence of scour | ROW 1.6.1(1)<br>ROW 2.3<br>ROW 3.1.1 | 🟩 | | ■ | | | | | | | | 1 | | |
| **Bank Migration Survey- -** Colville River | ►Measure distance from the top of the bank to the permanent baseline running parallel to each ank of the Colville River (East Channel) Pipeline Crossing<br>►Bank Migration reaching 50 percent of the design setback | ROW 1.6.1<br>ROW 2.3.2 | 🟦 | | ■ | | | | | | | | 1 | | |
| **Bank Migration Survey- -** Miluveach and Kachemach Rivers | ►Measure distance from the top of the bank to the permanent baseline running parallel to each ank of the Colville River (East Channel) Pipeline Crossing | ROW 1.6.1<br>ROW 2.3.2 | 🟦 | | ■ | | | | | | | | 5 | | |
| **Flooding** | ►Evidence of flooding that could threaten a facility or pipeline.<br>►Conditions which erode the banks or threaten a facility or pipeline.<br>►New river channels or ice dams at crossings. | ROW 1.6.1(1)<br>ROW 2.3 | 🟩 | ■ | | | | | | ■ | | | | | |
| | | | 🟦 | | ■ | | | | | | | | 1 | | |
| **Channel Obstruction** | ►Obstructions that threaten to cause erosion or flooding of pipeline facilities.<br>►Ice dams at crossings | ROW 1.6.1(1)<br>ROW 2.3 | 🟩 | | ■ | | | | | | | | 1 | | |
| **Channel Change** | ►Change in the river channel flow at river crossings. ►New river channels ►Channel changes where water cannot be diverted and there is: (1) Concentrated Longitudially flow on or along the pipeline centerline, (2) Gullying threatening the below grade pipe | ROW 1.6.1(1)<br>ROW 2.3 | 🟩 | | ■ | | | | | | | | 1 | | |

## SURVEILLANCE AND MONITORING PROGRAM

| DESCRIPTION QUANTITY/LOCATION | REPORTABLE CONDITIONS OR RATIONALE | REFERENCE ROW STIPULATION EXHIBIT A CRITERIA | ■ ■ | METHOD | | | | | | FREQUENCY QUANTITY | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ACTIVITY | Aerial | Ground | Leak Detect | IP21 | Pigging | Site Specific | Weekly | Monthly | Months (#) | Years (#) | Conditional | Continuous |
| **Depressions, Ponding, Humps or Swales** | ►Depressions occuring longitudinally over pipe axis, are deeper than 1-foot and are more than 100-feet long ►Ponding that extends over the pipe axis, deeper than 1-foot, and more than 100-feet long ►Pressure ridges developing parallel to the pipe axis and exceeding 1-foot in height and 60-feet in length | ROW 1.6.1(1)<br>ROW 2.3 | ■ | | ■ | | | | | | | | 1 | | |
| **Ground Cracking** | Cracks wtihin 10-feet of pipeline centerline having one of the following characteristicsL ►At least 10-feet long with vertical displacement exceeding 6-inches ►Wider than 2-inches, parallel to the pipe axis, and longer than 60-feet | ROW 1.6.1(1),(3) | ■ | | ■ | | | | | | | | 1 | | |
| **Ground Cracking** | Cracks wtihin 10-feet of pipeline centerline having one of the following characteristicsL ►At least 10-feet long with vertical displacement exceeding 6-inches ►Wider than 2-inches, parallel to the pipe axis, and longer than 60-feet | ROW 1.6.1(1),(3) | ■ | | ■ | | | | | | | | 1 | | |

### VALVES

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Mainline Valves - -** Alpine Oil | ►Inspect for damage ►Confirm proper functioning | ROW 1.6.1 | ■ | | ■ | | | | | | | 6 | | | |
| **Mainline Valves - -** Alpine Seawater | ►Inspect for damage ►Confirm proper functioning | ROW 1.6.1 | ■ | | ■ | | | | | | | | 3 | | |
| **Relief Valves** | ►Inspect for damage ►Confirm proper functioning | ROW 1.6.1 | ■ | | ■ | | | | | | | | 1 | | |

# 7 REPORTING

### 7.1.1 GENERAL

Surveillance and monitoring reporting is performed in accordance with Figure 7.1, Reporting Flow Chart.

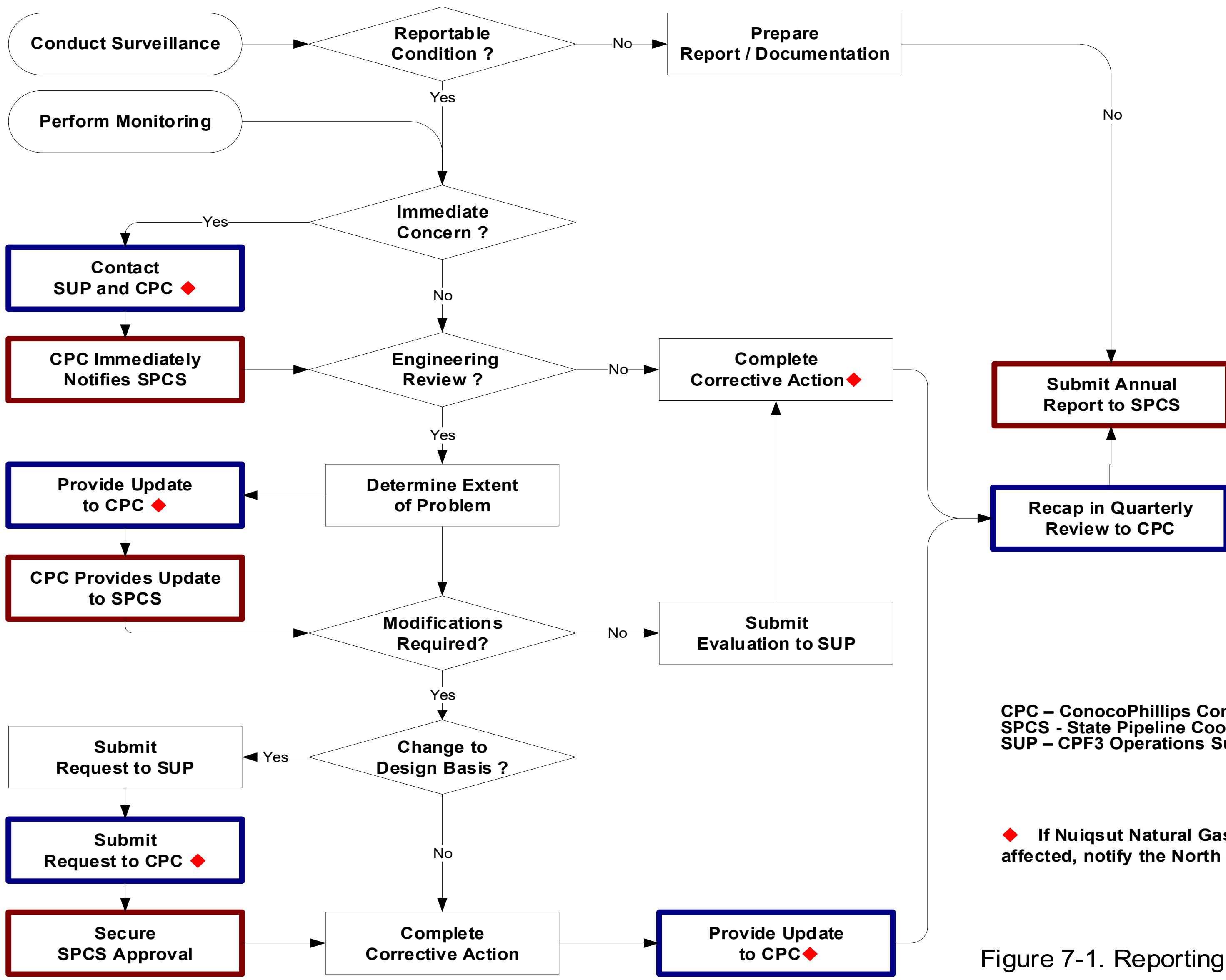
### 7.1.2 QUARTERLY REVIEW TO CPC

A quarterly review with the Regulatory Compliance Coordinator recaps current pipeline system surveillance and monitoring activities, provides the status of reportable conditions being addressed, and identifies other issues or anticipated changes. Format and content may vary (e.g., e-mail, briefing, written report, etc.), and includes:

- Location identifier (e.g., VSM, engineering station, etc.)
- Short activity description
- Contact and phone number (as needed)
- Current status
- Planned completion
- Issues or concerns impacting corrective action, as appropriate

### 7.1.3 ANNUAL REPORT TO COMMISSIONER

An annual submittal to the Commissioner provides a written analysis of pipeline system changes as documented by surveillance and monitoring records (e.g., pipeline inspections, forward looking infrared radar (FLIR) surveys, preventive maintenance and corrective action work orders, condition specific reports, etc.). This submission also identifies previous year and cumulative changes, effects of the changes, and proposed corrective and mitigation plans.




**CPC – ConocoPhillips Company**
**SPCS - State Pipeline Coordinator's Section**
**SUP – CPF3 Operations Superintendent**

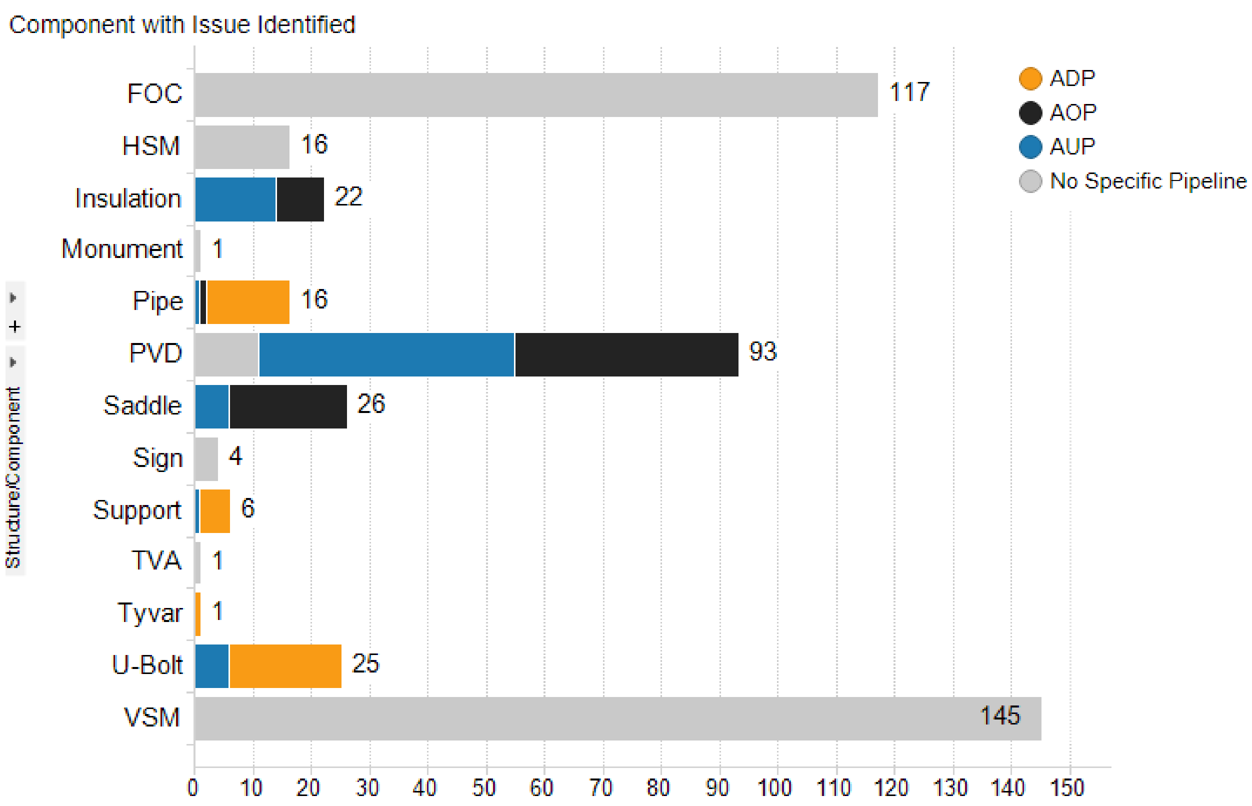
◆ **If Nuiqsut Natural Gas Pipeline is affected, notify the North Slope Borough.**

Figure 7-1. Reporting Flow Chart

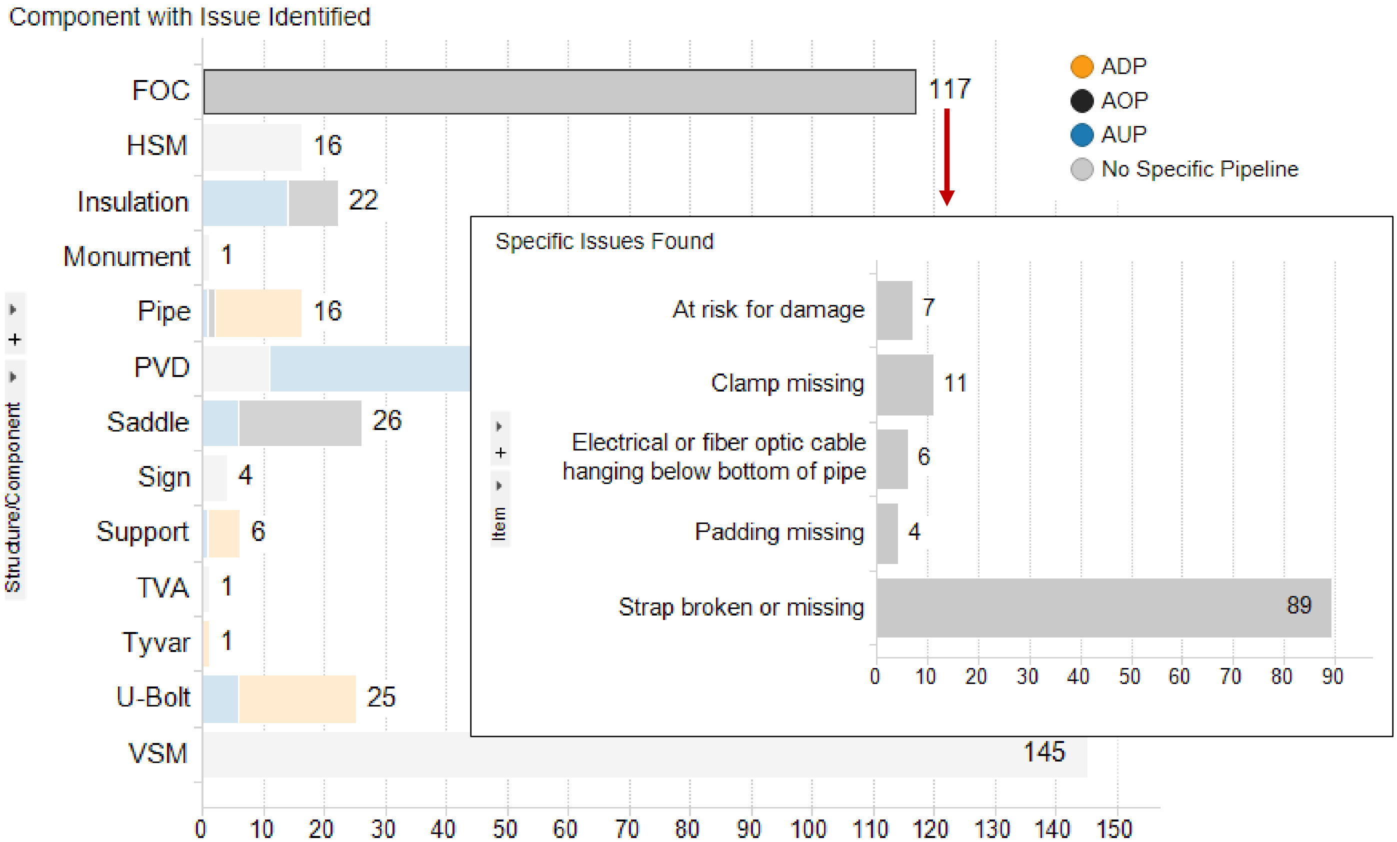
## Annual Mechanical Ground Inspection Results

The Annual Mechanical Ground Inspection is an integral part of the Surveillance and Monitoring Program. The annual inspection involves a physical walk-down of the pipelines with up to 28 inspection items completed at each VSM location, pipeline span, or monument location. In prior years, data has been collected within spreadsheets which are then used to sort results and are then forwarded to the appropriate disciplines for review and to construct repair plans. In 2018 we began developing a database solution to collect inspection data in a manner that will allow results to be routed to the appropriate discipline more efficiently and which provides the ability to perform effective data analysis.

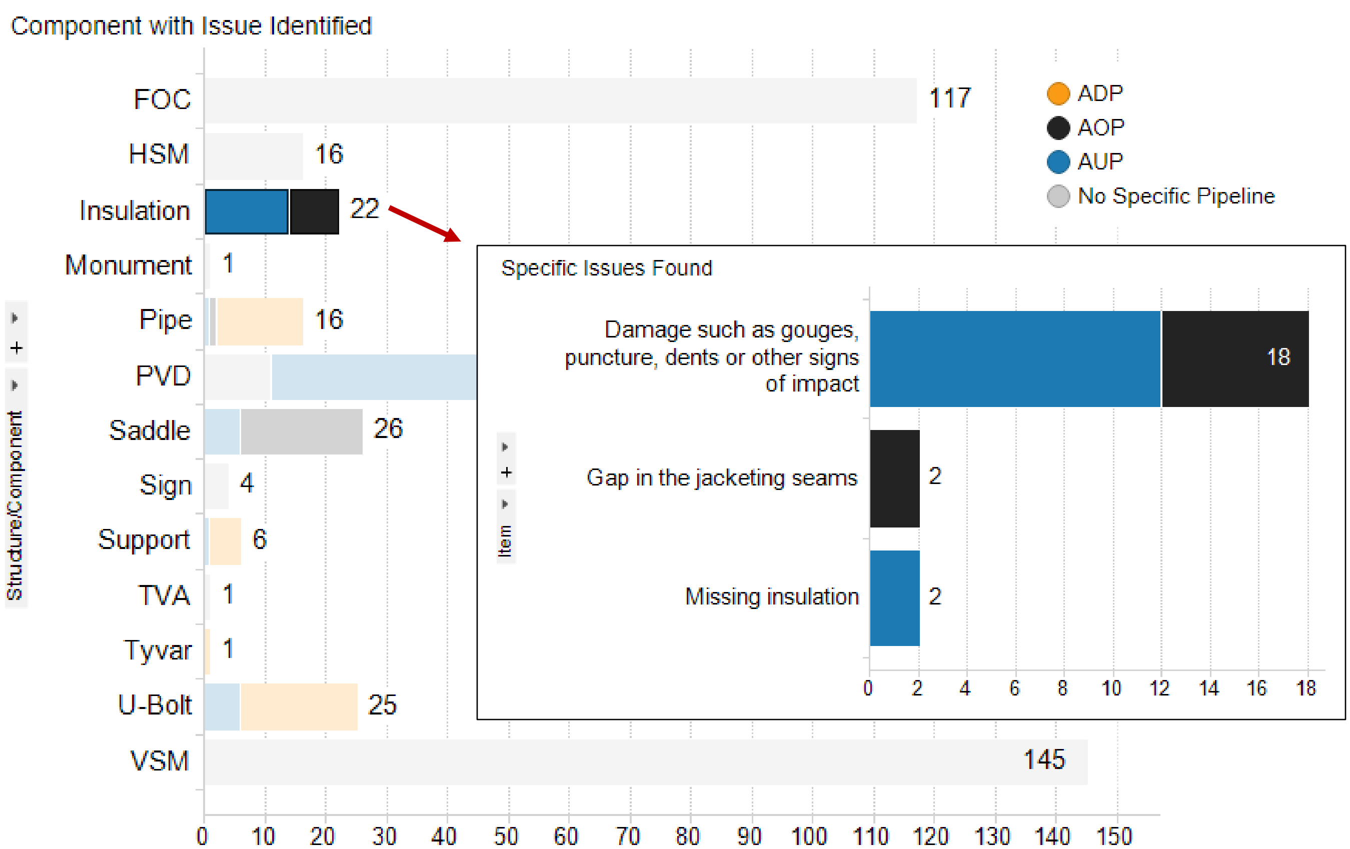
The results from the most recent Alpine Pipelines Mechanical Ground Inspection were transferred from the previously used spreadsheet to a newly formatted spreadsheet that will be the basis for the database concept currently in development. It is a first pass at identifying categories for collecting the data to ensure effective analysis. The following chart provides a snapshot of the number of issues identified per component type. The application used to create these charts allows Operations to identify the specific issues found per component. The charts on the following pages show the specific issues that were identified for the component category selected and the last page provides a breakdown of issues found in tabular form.



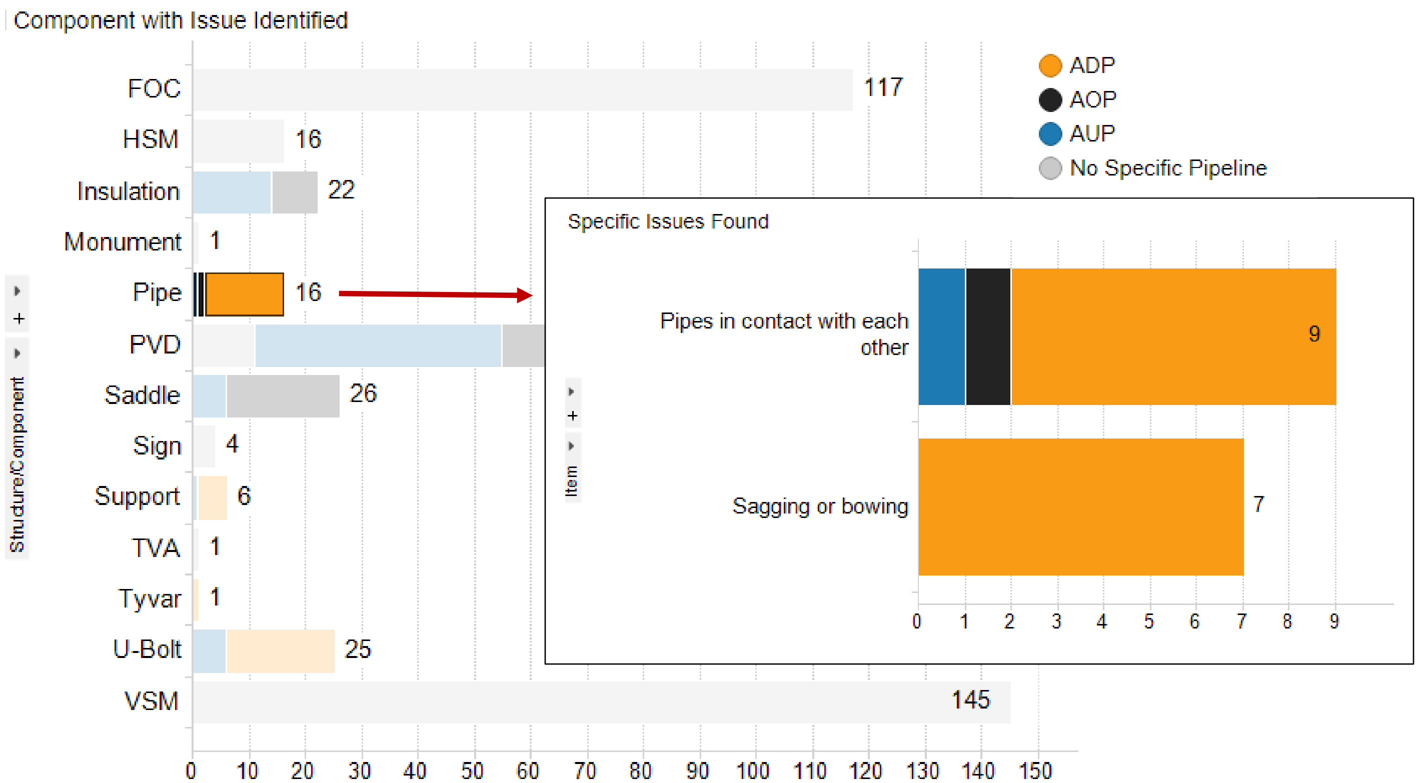

FOC = Fiber Optic Cable



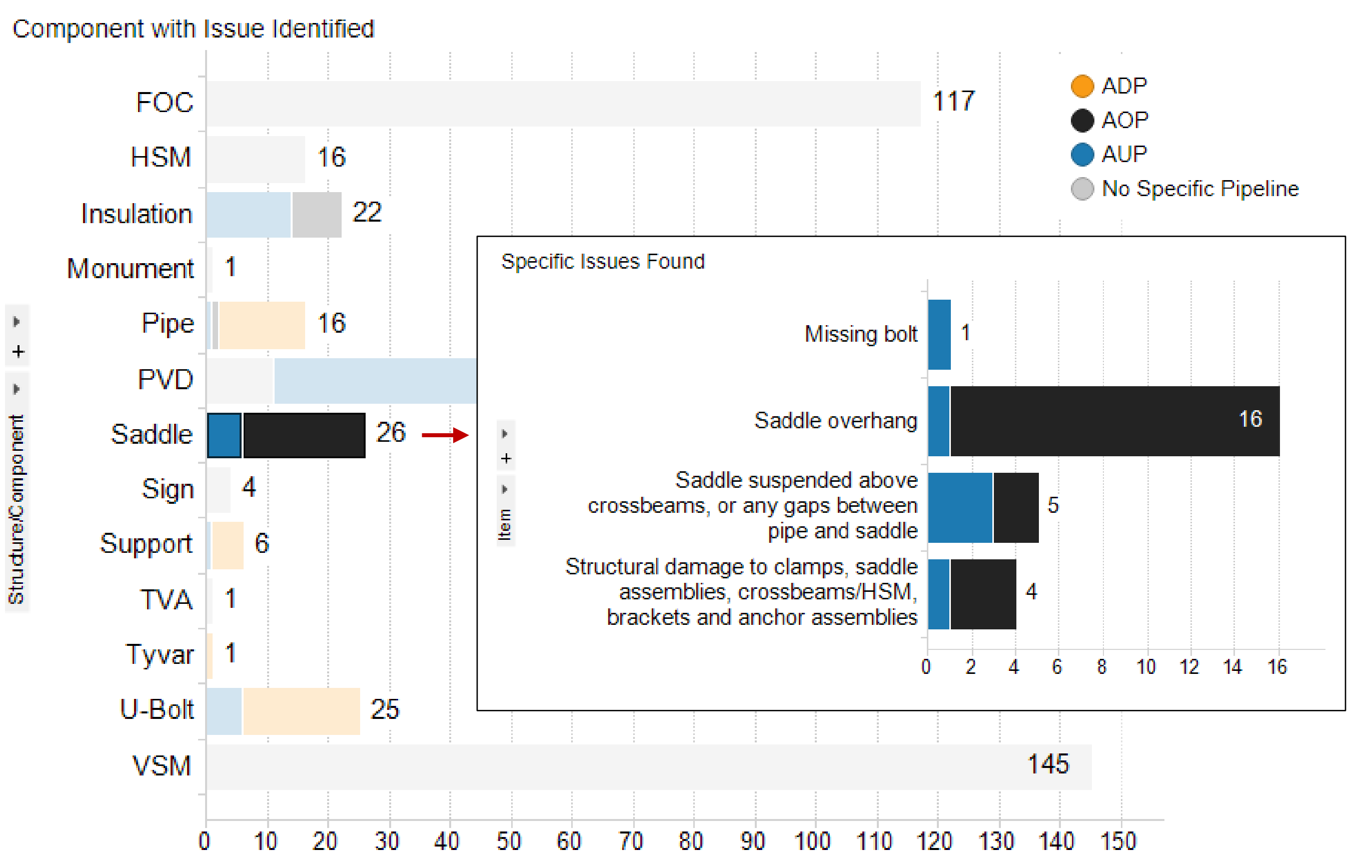
Component with Issue Identified
FOC 117
HSM 16
Insulation 22
Monument 1
Pipe 16
PVD
Saddle 26
Sign 4
Support 6
TVA 1
Tyvar 1
U-Bolt 25
VSM 145
Structure/Component
ADP
AOP
AUP
No Specific Pipeline
Specific Issues Found
At risk for damage 7
Clamp missing 11
Electrical or fiber optic cable hanging below bottom of pipe 6
Padding missing 4
Strap broken or missing 89
Item

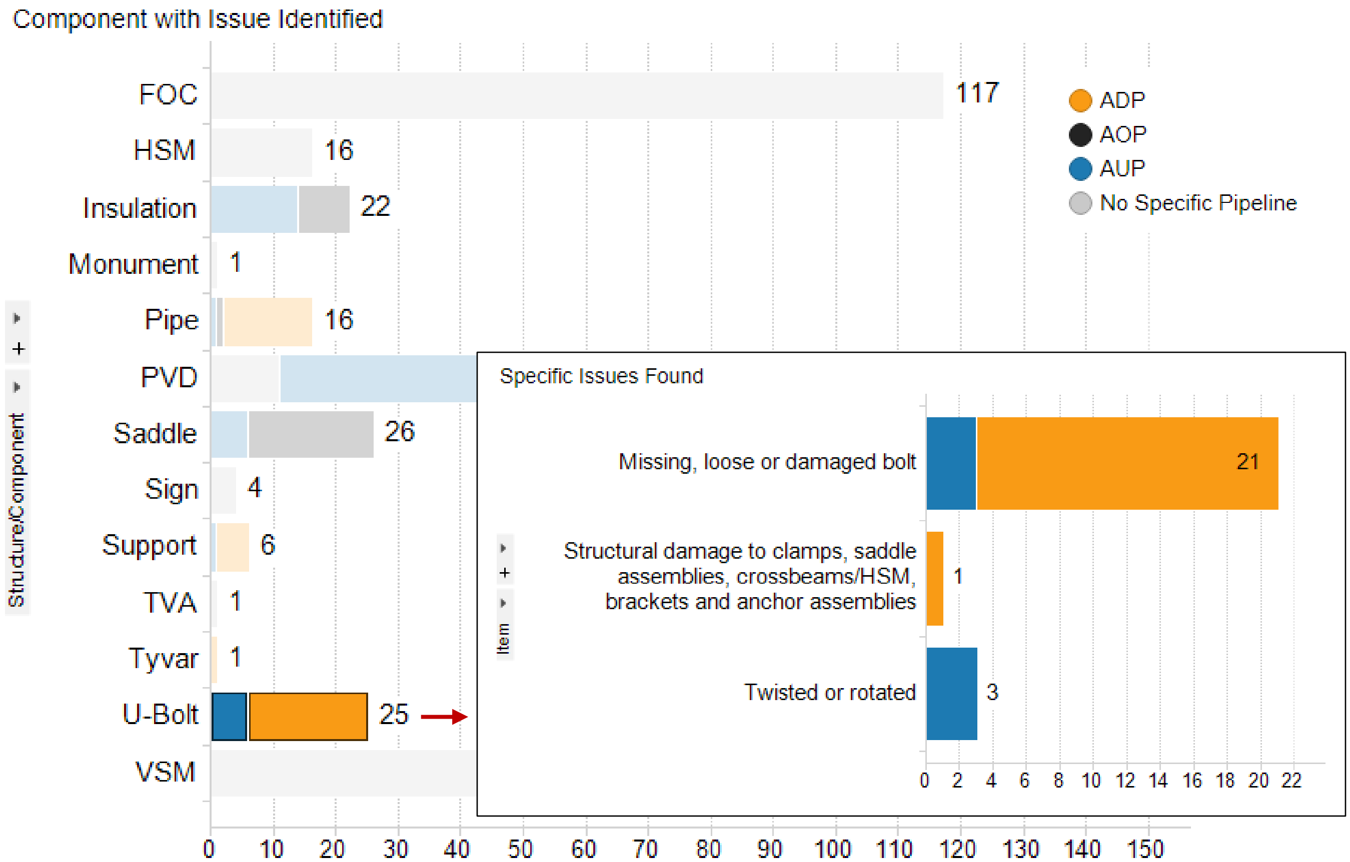
Component with Issue Identified
FOC 117
HSM 16
Insulation 22
Monument 1
Pipe 16
PVD
Saddle 26
Sign 4
Support 6
TVA 1
Tyvar 1
U-Bolt 25
VSM 145
Structure/Component
ADP
AOP
AUP
No Specific Pipeline
Specific Issues Found
Damage such as gouges, puncture, dents or other signs of impact 18
Gap in the jacketing seams 2
Missing insulation 2
Item



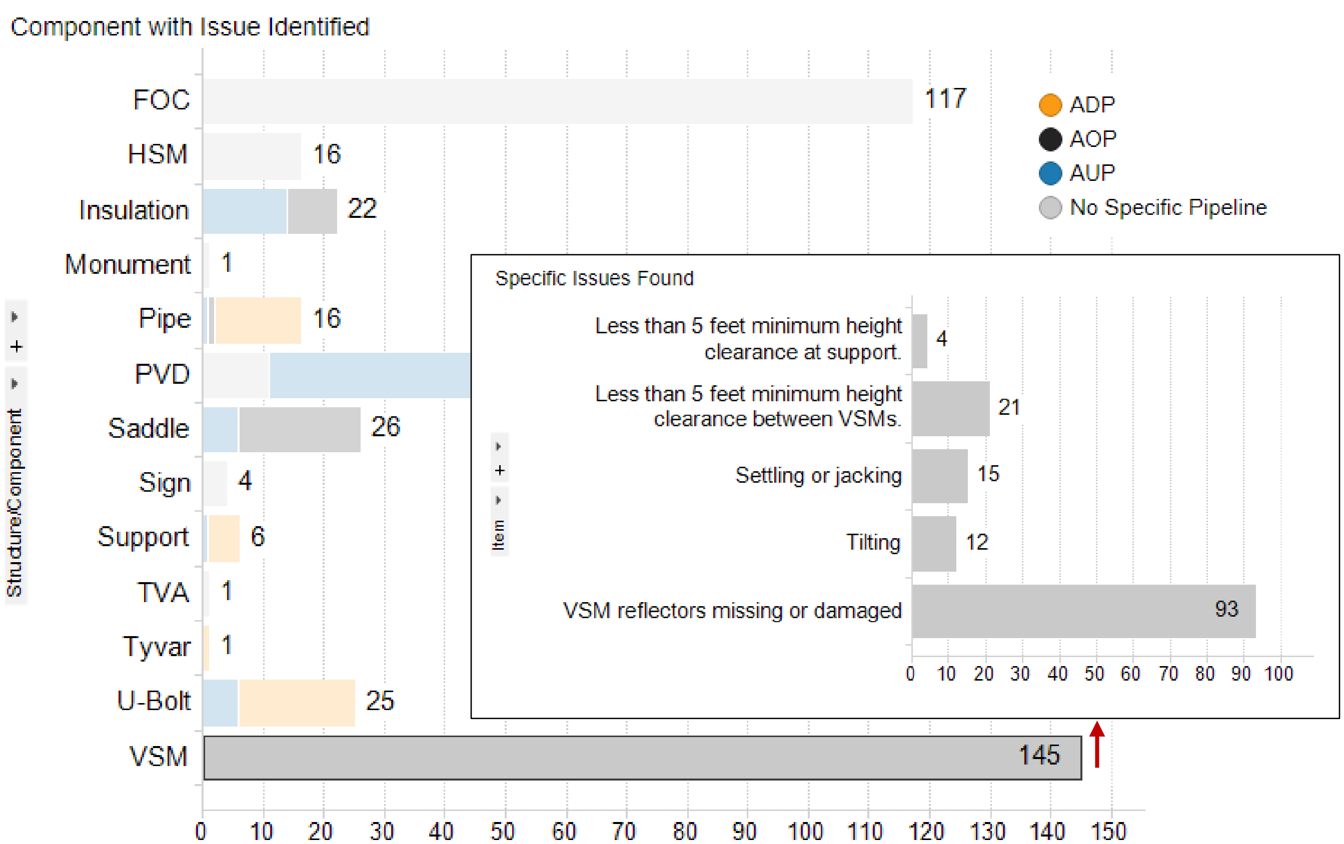
Component with Issue Identified
FOC 117
HSM 16
Insulation 22
Monument 1
Pipe 16
PVD
Saddle 26
Sign 4
Support 6
TVA 1
Tyvar 1
U-Bolt 25
VSM 145
Structure/Component
0 10 20 30 40 50 60 70 80 90 100 110 120 130 140 150
ADP
AOP
AUP
No Specific Pipeline
Specific Issues Found
Pipes in contact with each other 9
Sagging or bowing 7
Item
0 1 2 3 4 5 6 7 8 9

Component with Issue Identified
FOC 117
HSM 16
Insulation 22
Monument 1
Pipe 16
PVD
Saddle 26
Sign 4
Support 6
TVA 1
Tyvar 1
U-Bolt 25
VSM 145
Structure/Component
0 10 20 30 40 50 60 70 80 90 100 110 120 130 140 150
ADP
AOP
AUP
No Specific Pipeline
Specific Issues Found
Missing bolt 1
Saddle overhang 16
Saddle suspended above crossbeams, or any gaps between pipe and saddle 5
Structural damage to clamps, saddle assemblies, crossbeams/HSM, brackets and anchor assemblies 4
Item
0 2 4 6 8 10 12 14 16



Component with Issue Identified
FOC
117
HSM
16
Insulation
22
Monument
1
Pipe
16
PVD
Saddle
26
Sign
4
Support
6
TVA
1
Tyvar
1
U-Bolt
25
VSM
Structure/Component
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
ADP
AOP
AUP
No Specific Pipeline
Specific Issues Found
Missing, loose or damaged bolt
21
Structural damage to clamps, saddle assemblies, crossbeams/HSM, brackets and anchor assemblies
1
Twisted or rotated
3
Item
0
2
4
6
8
10
12
14
16
18
20
22

Component with Issue Identified
FOC
117
HSM
16
Insulation
22
Monument
1
Pipe
16
PVD
Saddle
26
Sign
4
Support
6
TVA
1
Tyvar
1
U-Bolt
25
VSM
145
Structure/Component
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
ADP
AOP
AUP
No Specific Pipeline
Specific Issues Found
Less than 5 feet minimum height clearance at support.
4
Less than 5 feet minimum height clearance between VSMs.
21
Settling or jacking
15
Tilting
12
VSM reflectors missing or damaged
93
Item
0
10
20
30
40
50
60
70
80
90
100

The following shows the breakdown of the Issues by Component in a tabular form.

| Structure/ Component | Item | ADP | AOP | AUP | Non-Pipeline Specific |
|---|---|---|---|---|---|
| FOC | At risk for damage | | | | 7 |
| | Clamp missing | | | | 11 |
| | Electrical or fiber optic cable hanging below bottom of pipe | | | | 6 |
| | Padding missing | | | | 4 |
| | Strap broken or missing | | | | 89 |
| HSM | HSM Rotated | | | | 10 |
| | Visibly sloping HSM | | | | 6 |
| Insulation | Damage such as gouges, puncture, dents or other signs of impact | | 6 | 12 | |
| | Gap in the jacketing seams | | 2 | | |
| | Missing insulation | | | 2 | |
| Monument | Other | | | | 1 |
| Pipe | Pipes in contact with each other | 7 | 1 | 1 | |
| | Sagging or bowing | 7 | | | |
| PVD | Missing, damaged, or broken PVD or TVA | | 38 | 44 | 11 |
| Saddle | Missing bolt | | | 1 | |
| | Saddle overhang | | 15 | 1 | |
| | Saddle suspended above crossbeams, or any gaps between pipe and saddle | | 2 | 3 | |
| | Structural damage to clamps, saddle assemblies, crossbeams/HSM, brackets and anchor assemblies | | 3 | 1 | |
| Sign | Damaged or missing signs or markers for pipeline, module or CPF2 Divert Tank (T1-P201A): identification, restricted access, etc. | | | | 1 |
| | Other | | | | 3 |
| Support | Twisted or rotated | 5 | | 1 | |
| TVA | Missing, damaged, or broken PVD or TVA | | | | 1 |
| Tyvar | Damaged or missing Tyvar pads at U-bolt locations | 1 | | | |
| U-Bolt | Missing, loose or damaged bolt | 18 | | 3 | |
| | Structural damage to clamps, saddle assemblies, crossbeams/HSM, brackets and anchor assemblies | 1 | | | |
| | Twisted or rotated | | | 3 | |
| VSM | Less than 5 feet minimum height clearance at support. | | | | 4 |
| | Less than 5 feet minimum height clearance between VSMs. | | | | 21 |
| | Settling or jacking | | | | 15 |
| | Tilting | | | | 12 |
| | VSM reflectors missing or damaged | | | | 93 |

# DOCUMENT SUMMARY

This procedure outlines the corrosion control program used to ensure the mechanical integrity of the Alpine Crude Oil Pipeline (APL). Discussion includes responsibilities, regulatory requirements, external and internal corrosion monitoring and mitigation, and documentation retention.

## RESPONSIBILITIES

### ALASKA ASSET INTEGRITY (AI)

The Alaska Asset Integrity (AI) Corrosion Team are responsible for developing and implementing this program, which includes monitoring, inspecting and testing, and evaluating and recommending repairs and operating changes. Drawing APLM-00CO-D-08 *Pipeline Specifications* summarizes the key pipe specifications used for the APL.

### CORROSION ENGINEER

The Corrosion Engineer is responsible for:

- Evaluating field results to identify corrosion abnormalities that may affect the pipeline's ability to operate at its designed maximum operating pressure (MOP).
- Immediately reporting such abnormalities to the CPF3 Operations Superintendent for review, approval, and corrective action, as necessary.

### ALASKA AI SUPERINTENDENT

The Alaska AI Superintendent is responsible for:

- Overseeing the APL Corrosion Program.
- Making sure inspection, monitoring results, evaluations and repair recommendations are consistent with applicable regulatory or industry code and standard requirements or commitments.

- Making sure results and recommendations are communicated to the CPF3 Operations Superintendent for review, approval, and corrective action, as necessary.

### MECHANICAL INSPECTION TEAM

The Mechanical Inspection Team is responsible to conduct an inspection of the permanent insulation along the pipeline to identify areas of atmospheric corrosion susceptibility.

### CPF3 OPERATIONS SUPERINTENDENT

The CPF3 Operations Superintendent is responsible for:

- Cathodic protection (CP) system maintenance.
- Routine maintenance pigging.
- Responding to corrosion control corrective action recommendations.

### OPERATOR QUALIFICATION

This procedure includes the following covered tasks requiring Operator Qualification (OQ) prior to performance.

| Responsible Party | OQ | Task Description |
|---|---|---|
| Corrosion Personnel | 4232 | Corrosion Control Access Tools |
| Corrosion Personnel | 4241 | Bi-Monthly Rectifier Monitoring |
| Corrosion Personnel | 4620 | NDE Inspection – Non-Destructive Examination |
| Corrosion Personnel | 4242 | HDD CP System Polarization Decay Test |
| Mechanical Inspection Personnel | 4514 | Inspect Pipeline Right-Of-Way – Mechanical |
| Operations Personnel | 4233 | Pipeline Pigging – Perform |
| Operations Personnel | 4322 | Pipeline Valves, Inspect and Operate |

## REGULATORY REQUIREMENTS

### DEPARTMENT OF TRANSPORTATION (DOT) JURISDICTION

The APL is under Department of Transportation (DOT) jurisdiction and CPAI performs Corrosion Program activities and retains the required records in accordance with DOT regulations 49 CFR 195, Subpart H, Corrosion Control, and 195.452, Pipeline Integrity Management in High Consequence Areas.

### STATE OF ALASKA – RIGHT-OF-WAY LEASE AND STIPULATIONS

Section 14(c) and Exhibit A, Stipulation 1.6.1, of the Alpine Oil Pipeline, Right-of-Way Lease, ADL 415701, requires a Surveillance and Monitoring Program to detect and abate situations that may endanger health, safety, environment or the integrity of the pipeline system. In addition, Stipulation 3.2.1 requires early detection of corrosion in accordance with the application, state requirements, and 49 CFR 195.

### MINIMUM REQUIREMENTS

| Category | Governing Reference | Minimum Frequency | Task |
|---|---|---|---|
| Internal / External Corrosion | 195.452(j)(3)<br>195.452(j)(5)(i)<br>195.579(a)<br>195.583 | Every 2 years [1] | Perform instrumented (smart) pigging |
| External Corrosion | ROW 1.6.1 | Annually | Inspect below grade crossings to ensure free of debris |
| External Corrosion Susceptibility | 195.581<br>195.583 | Every 3 years<br>NTE 39M | Inspect the pipe insulation system for locations susceptible to water ingress |
| External Corrosion | 195.581<br>195.583 | Every 3 years<br>NTE 39M | Inspect for atmospheric corrosion |
| Internal Corrosion | 195.452(j)(5)(iv)<br>195.579(a) | Every 3 years | Inspect un-piggable elevation change elbows for condition and solids build-up |
| Internal Corrosion | 195.579(a) | Every 3 years | Inspect un-piggable sections of pipe for condition |
| Internal Corrosion | 195.579(c) | When open | Inspect for internal condition |
| Internal Corrosion | 195.579(b)(3) | Every 6 months<br>NTE 7½M | Pull corrosion coupons for evaluation |
| Internal Corrosion | 195.579(a) | Monthly | Perform maintenance pigging |
| Cathodic Protection | 195.573(c) [2] | Every 2 months<br>NTE 2½M | Confirm and record rectifier readings |
| Cathodic Protection | 195.575<br>195.577 [2] | Annually | Confirm system functioning (casing isolation) |

| Category | Governing Reference | Minimum Frequency | Task |
|---|---|---|---|
| Cathodic Protection | 195.571<br>159.573(a)(1)<br>195.573(e) [2] | Annually | Polarization Decay Testing |
| HDD Thaw Settlement | ROW | Every 4 years [3] | Instrumented (smart) pigging<br>Inertial Navigation (geometry) Pig |

* NTE = Not to Exceed

NOTES:

1. 195.452(j)(5)(i) requires inspection intervals not to exceed 5 years. As approved in the SPCS Surveillance and Monitoring Program and as referenced in the Alpine Oil Pipeline *Analysis of Aboveground pipeline and Aboveground River Crossings – Supplemental Information*, submitted to State Pipeline Coordinator in June 2002, corrosion pigging will take place at least every two years.

2. The Alpine carrier pipelines at the Colville River crossing transition below the river within a drilled (air annulus) casing. As such, these pipelines are not buried or submerged by DOT definition and CP of the pipeline is not required. CP was applied to the casing as a best practice and the leak detection system is used to confirm the integrity of the casing. Should the casing fail, the pipelines would meet the definition of buried or submerged pipelines, and would require CP according to §195.563.

3. Incorporated by reference into the Alpine Oil Pipeline Right-of-Way Lease and Stipulations, the Colville River Crossing Design Report, Revision 3, May 1999, requires the gathering of thaw settlement data using smart pigs in 2001, 2003, and 2005, to determine the extent of thaw settlement and evaluate the stress and strain in the pipelines compared against the allowable levels previously established. In 2005, the frequency of smart pig runs must be evaluated and program adjusted as necessary.

## *PRECAUTIONS AND LIMITATIONS*

### *ABNORMAL OPERATING CONDITIONS (AOC)*

The following are the AOC that could be encountered while performing this procedure and the appropriate response to make should the AOC be encountered:

| Abnormal Operating Condition | Appropriate Response |
|---|---|
| Leak or unintended release of hydrocarbon from a pipeline component | • Make appropriate notifications<br>AND<br>• If authorized, initiate emergency shutdown/ isolation of pipeline facility and/or component |
| Fire or explosion due to a release of hydrocarbon | • Make appropriate notifications<br>AND<br>• If authorized, activate emergency shutdown and response |

| Abnormal Operating Condition | Appropriate Response |
|---|---|
| Malfunction of a pipeline component during the course of performing a covered task | • Make appropriate notifications<br>AND<br>• If authorized, initiate emergency shutdown/ isolation of pipeline facility and/or component |
| Physical damage of a pipeline facility or component | • Make appropriate notifications |
| Unauthorized right-of-way activity | • Make appropriate notifications<br>OR<br>• If authorized and if the situation requires, attempt to stop activity |

## PROCEDURE

These procedures are minimum requirements. Some situations may require additional actions to achieve an adequate margin of safety.

This program provides a brief overview of the pipeline and liquid characteristics that may create external or internal corrosion.

## PIPELINE AND LIQUID CHARACTERISTICS

### PIPELINE

External corrosion typically is caused by water ingress into the insulation system. Shop-applied insulation is initially impervious to water penetration. However, it can become susceptible to external corrosion when water penetrates the insulation system which can occur at the following locations:

- Field-weld insulation packs. The exception is weld packs installed or replaced after 1998. The newer weld pack design includes a petrolatum (Denso) tape wrap to prevent any water that may penetrate the sheathing from contacting the pipe.
- Sites where the shop-applied insulation sheathing is damaged.
- Shop applied sheathing with missing bands resulting in gaps.
- Dead-legs and attachments that protrude from the insulated pipe.

- Branch connections.
- Flange and valve areas.
- Piping with factory applied insulation within 4 feet of a field applied insulation interface.
- Piping with factory applied insulation in a saddle.

### LIQUID

The APL carries sales quality crude oil with a maximum sediment and water content of 0.35 volume percent. The risk of internal corrosion with this low water-low sulfur content crude product is very small. Because of the low corrosivity, corrosion inhibitor is not utilized in the APL. However, water dropout in the APL is thermodynamically possible.

## INSPECTION

To control corrosion, CPAI performs inspection activities in accordance with the Integrity Management Program (IMP) Inspection Section. A brief summary of techniques is provided in this section.

### VISUAL INSPECTIONS

There are two components of visual inspection, inspection of the permanent insulation system to identify susceptible locations for water ingress and visual inspection of piping and piping components for external and internal corrosion. The following describes what is included in each type of visual inspection.

Visual inspections of the permanent insulation system to identify susceptible locations along the unpiggable portions of the pipeline is completed by Corrosion Personnel within the Asset Integrity group. Visual inspection of the insulation system to identify susceptible locations along the piggable portion of the pipeline is completed by the Mechanical Inspection Personnel. These two groups identify and document locations susceptible to atmospheric corrosion as outlined above which have not been previously identified. For example, flange and valve areas will likely already be identified. The newly identified locations will be assessed to determine the potential for external corrosion. If a location could lead to corrosion problems prior to the next inspection, it will be added to the inspection list for external corrosion inspection which will be completed using one of the following techniques:

- Instrumented (Smart) Pig Inspection
- Tangential Radiographic Inspection

Visual Inspection of piping and piping components for external corrosion is completed for all locations that do not have permanent insulation, including any location with removeable insulation blankets or bags and non-insulated areas that are exposed to the atmosphere. This also includes locations in which the permanent insulation has been removed for internal corrosion monitoring, including Known Damage Reporting (KDR) and Corrosion Rate Monitoring (CRM) sites. Inspection intervals are once every three years not to exceed thirty-nine months.

Visual internal corrosion inspection of the pipe wall surface is performed whenever pipe is removed and the internal surfaces are available for inspection. If corrosion is found, the adjacent pipe is investigated both longitudinally and circumferentially to determine the extent of the corrosion.

Additionally, each of the cased below grade crossings is visually inspected each year to ensure debris and water are not accumulating in the casing and pipe annulus.

### *INSTRUMENTED (SMART) PIG INSPECTIONS*

An instrumented (smart) pig capable of detecting corrosion damage is run through the piggable segment of the APL. The 14-inch line segment is the only line portion that is piggable.

### *TANGENTIAL RADIOGRAPHIC INSPECTION*

Tangential radiography (TRT) of the APL is performed during ILI follow-up to detect and monitor external corrosion damage and evaluate the extent of any water ingress into the weld pack or damaged metal sheathing that could lead to future corrosion problems.

Unpiggable APL segments are inspected on a 3-year cycle. Insulation sheathing is visually inspected as described above. TRT is performed on the identified susceptible areas that could lead to corrosion problems prior to the next inspection, and at weld packs that have not been refurbished with petrolatum (Denso) tape.

### *ULTRASONIC OR RADIOGRAPHIC INSPECTIONS*

Ultrasonic (UT) or radiographic (RT) techniques are used to confirm results from other techniques, such as instrumented (smart) pigging or visual inspection, when deemed necessary. These techniques are also used for the un-piggable pipeline segments at the Corrosion Engineer's discretion to check for internal pipe wall corrosion.

### *LONG RANGE ULTRASONIC TESTING*

Long Range Ultrasonic Testing (LRUT) is used to inspect below-grade pipes under caribou crossings, roads and gravel pads. This technique is primarily used as a screening method to determine if the pipe should be excavated for further inspection using RT or UT.

TRT, UT, RT and LRUT are not assessment methods identified within 49 CFR 195.452(j)(5) and therefore, according to 49 CFR 195.452(j)(5)(iv) require a notification be sent to PHMSA 90 days before conducting the assessment. For more information on this requirement refer to the Liquids Management Integrity Program.

### *CORROSION COUPONS*

To assist in monitoring internal corrosion potential, coupons are located at the inlet and outlet of the primary pipeline segments. Coupons are removed and evaluated twice per year at an interval not to exceed 7-1/2 months. If coupon corrosion rates exceed three mils per year general or ten mils per year pitting, the cause will be investigated.

## MITIGATION

CPAI uses maintenance pigging and cathodic protection to mitigate corrosion as described herein.

### MAINTENANCE PIGGING

The APL is maintenance pigged monthly to reduce water dropout and sediment accumulation potential. If there is a need to change this schedule temporarily for operational needs, the Corrosion Engineers are consulted and appropriate approvals secured.

### CATHODIC PROTECTION

The majority of the APL is supported by an aboveground system composed of vertical and horizontal support members. Exceptions are the Colville River crossing and Road Crossings.

#### COLVILLE RIVER CROSSING

At the Colville River crossing, the pipeline transitions below the river within an 18-inch drilled air-annulus casing. Since the line is not buried or submerged by DOT definition, there is no cathodic protection system on the pipeline.

As a best practice, CP has been applied to the casing and a leak detection system is used to confirm its integrity. Should the casing fail, the DOT pipelines would then meet the definition of buried or submerged pipelines and would require CP according to 195.563. APLM-0000-CO-0046, “HDD Cathodic Protection Normal Operating Procedures”, provides a detailed system description, and APLM-0000-CO-0045, “HDD Cathodic Protection System Performance Testing” describes rectifier readings and annual system testing.

#### ROAD CROSSINGS

At road crossings, the pipeline is also routed below grade within an air-annulus casing. None of the pipe surface is exposed to soil or gravel. Since the line is not buried or submerged by DOT definition, there is no cathodic protection system on the pipeline.

## *REMEDIATION*

If inspection techniques indicate either general corrosion or localized pitting has occurred, pipeline remediation is performed in accordance with the Integrity Management Program Remediation Strategy.

### *DOCUMENTATION*

The CPAI Corrosion Team retains documentation pertaining to corrosion program activities on the SWPL in the North Slope AI Corrosion files or database in accordance with 195.589( c). This includes:

- APL inspection reports (including visual, TRT, UT, and RT inspection results)
- Pipe strength calculations
- Instrumented (smart) pig results
- Annual road crossing casing visual inspection results
- Corrosion coupon results.

Cathodic protection and maintenance pigging records are retained in the Alpine SAP Document Management System (DMS) database.

## *REFERENCES*

The listed documents are not by reference part of this procedure. Reference is made only to the paragraph or section listed and not the entire document

### *INDUSTRY STANDARDS*

| | |
|---|---|
| ASME B31.G | Manual for Determining the Remaining Strength of Corroded Pipelines |
| RSTRENG | AGA, Project PR-3-805, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe” |

## *COMPANY REFERENCES*

| | |
|---|---|
| APLM-0000-CO-0045 | HDD Cathodic Protection System Performance Testing |
| APLM-0000-CO-0046 | HDD Cathodic Protection Normal Operating Procedure |

**(End of Document)**

## REVISION / APPROVAL LOG

| Rev. No. | Date | Action | By |
|---|---|---|---|
| 15 | April 27, 2011 | Converted to new format | Alpine Pipeline Coordinator |
| 16 | May 13, 2011 | - Revise 4232 and 4233.3 AOCs to conform with OQ Program Appendix A.<br>- Change HDD Thaw Settlement Geometry Pig frequency to every 4 years. | Gary Haught |
| 17 | June12, 2012 | Replaced OQ 4221 and 4231 with new OQ 4620 | M. Undesser |
| 18 | Oct 5,2012 | Moved DOT Reference to NSPL 5502<br>Removed TOC<br>Added atmospheric corrosion to Visual Inspections section | Dan Schmidt |
| 19 | Nov 5, 2012 | Updated OQ 4232 title to Corrosion Control Access Tools | A. Peltier |
| 20 | Jan 29, 2013 | Renamed OQ 4233.3 to OQ 4233 Pipeline Pigging - Perform | M. Undesser |
| 21 | Sept 19, 2014 | Added OQ and AOC information. | Dan Schmidt |
| 22 | Oct 14, 2014 | Changed header and footer to current standard | Alpine Pipeline Coordinator |
| 23 | 11/01/16 | Removed 195.569, DOT regulation for below-grade debris inspection, and unpiggable from smart-pig section. Clarified table notes and visual inspection requirement. | K. McCullough |
| 24 | 12/26/16 | Formatted to current template | K. McCullough |

| Rev. No. | Date | Action | By |
|---|---|---|---|
| 25 | 07/06/2017 | Additional information for identifying locations within the pipeline insulation system that are considered susceptible to water ingress and therefore external corrosion. Includes the requirement for the 90-day notice to PHMSA prior to using TRT, UT, RT and LRUT to assess external corrosion. | N/A |

# DOCUMENT SUMMARY

This procedure outlines the corrosion control program used to ensure the mechanical integrity of the Alpine Arctic Heating Fuel Pipeline (AHFP). Discussion includes responsibilities, regulatory requirements, external and internal corrosion monitoring and mitigation, and documentation retention.

## RESPONSIBILITIES

### ALASKA ASSET INTEGRITY (AI)

The Alaska Asset Integrity (AI) Corrosion Team are responsible for developing and implementing this program, which includes monitoring, inspecting and testing, and evaluating and recommending repairs and operating changes. Drawing APLM-00SD-D-08 *Pipeline Specifications* summarizes the key pipe specifications used for the AHFP.

### CORROSION ENGINEER

The Corrosion Engineer is responsible for:

- Evaluating field results to identify corrosion abnormalities that may affect the pipeline's ability to operate at its designed maximum operating pressure (MOP).
- Immediately reporting such abnormalities to the CPF3 Operations Superintendent for review, approval, and corrective action, as necessary.

### ALASKA AI SUPERINTENDENT

The Alaska AI Superintendent is responsible for:

- Overseeing the AHFP Corrosion Program.
- Making sure inspection, monitoring results, evaluations and repair recommendations are consistent with applicable regulatory or industry code and standard requirements or commitments.

- Making sure results and recommendations are communicated to the CPF3 Operations Superintendent for review, approval, and corrective action, as necessary.

## *CPF3 OPERATIONS SUPERINTENDENT*

The CPF3 Operations Superintendent is responsible for:

- Cathodic protection (CP) system maintenance.
- Routine maintenance pigging.
- Responding to corrosion control corrective action recommendations.

## *OPERATOR QUALIFICATION*

This procedure includes the following covered tasks requiring Operator Qualification (OQ) prior to performance.

| Responsible Party | OQ | Task Description |
|---|---|---|
| Corrosion Personnel | 4232 | Corrosion Control Access Tools |
| Corrosion Personnel | 4241 | Bi-Monthly Rectifier Monitoring |
| Corrosion Personnel | 4620 | NDE Inspection – Non-Destructive Examination |
| Corrosion Personnel | 4242 | HDD CP System Polarization Decay Test |
| Operations Personnel | 4233 | Pipeline Pigging – Perform |
| Operations Personnel | 4322 | Pipeline Valves, Inspect and Operate |

## *REGULATORY REQUIREMENTS*

### *DEPARTMENT OF TRANSPORTATION (DOT) JURISDICTION*

The APL is under Department of Transportation (DOT) jurisdiction and CPAI performs Corrosion Program activities and retains the required records in accordance with DOT regulations 49 CFR 195, Subpart H, Corrosion Control, and 195.452, Pipeline Integrity Management in High Consequence Areas.

## *STATE OF ALASKA – RIGHT-OF-WAY LEASE AND STIPULATIONS*

Section 14(c) and Exhibit A, Stipulation 1.6.1, of the Alpine Diesel Pipeline, Right-of-Way Lease, ADL 415932, requires a Surveillance and Monitoring Program to detect and abate situations that may endanger health, safety, environment or the integrity of the pipeline system. In addition, Stipulation 3.2.1 requires early detection of corrosion in accordance with the application, state requirements, and 49 CFR 195.

## *MINIMUM REQUIREMENTS*

| Category | Governing Reference | Minimum Frequency | Task |
|---|---|---|---|
| Internal / External Corrosion | 195.452(j)(3)<br>195.452(j)(5)(i)<br>195.579(a)<br>195.583 | Every 5 years | Perform pressure test |
| External Corrosion | ROW 1.6.1 | Annually | Inspect below grade crossings to ensure free of debris |
| External Corrosion | 195.581<br>195.583 | Every 3 years<br>NTE 39M | Inspect for Atmospheric Corrosion |
| External Corrosion | 195.452(j)(3)<br>195.452(j)(5)(iii)<br>195.583<br>195.588 | Every 3 years | Inspect un-piggable sections of pipe for condition |
| Internal Corrosion | 195.452(j)(5)(iv)<br>195.579(a) | Every 3 years | Inspect un-piggable elevation change elbows for condition and solids build-up |
| Internal Corrosion | 195.579(c) | When open | Inspect for internal condition |
| Internal Corrosion | 195.579(b)(3) | Every 6 months<br>NTE 7 1/2 | Pull corrosion coupons for evaluation |
| Internal Corrosion | 195.579(a) | Quarterly | Perform maintenance pigging |
| Cathodic Protection | 195.573(c) [1] | Every 2 months<br>NTE 2 ½M | Confirm and record rectifier readings |
| Cathodic Protection | 195.575 195.577 [1] | Annually | Confirm system functioning (casing isolation) |
| Cathodic Protection | 195.571<br>159.573(a)(1)<br>195.573(e) [1] | Annually | Polarization Decay Testing |
| HDD Thaw Settlement | ROW | Every 4 years [2] | Instrumented (smart) pigging<br>Inertial Navigation (geometry) Pig |

*NTE=Not to Exceed

NOTES:

1. The Alpine carrier pipelines at the Colville River crossing transition below the river within a drilled (air annulus) casing. As such, these pipelines are not buried or submerged by DOT definition and CP of the

pipeline is not required. CP was applied to the casing as a best practice and the leak detection system is used to confirm the integrity of the casing. Should the casing fail, the pipelines would meet the definition of buried or submerged pipelines, and would require CP according to §195.563.

2. Incorporated by reference into the Alpine Diesel Pipeline Right-of-Way Lease and Stipulations, the Colville River Crossing Design Report, Revision 3, May 1999, requires the gathering of thaw settlement data using smart pigs in 2001, 2003, and 2005, to determine the extent of thaw settlement and evaluate the stress and strain in the pipelines compared against the allowable levels previously established. In 2005, the frequency of smart pig runs must be evaluated and program adjusted as necessary.

## PRECAUTIONS AND LIMITATIONS

### ABNORMAL OPERATING CONDITIONS (AOC)

The following are the AOC that could be encountered while performing this procedure and the appropriate response:

| Abnormal Operating Condition | Appropriate Response |
|---|---|
| Leak or unintended release of hydrocarbon from a pipeline component | • Make appropriate notifications<br>AND<br>• If authorized, initiate emergency shutdown/ isolation of pipeline facility and/or component |
| Fire or explosion due to a release of hydrocarbon | • Make appropriate notifications<br>AND<br>• If authorized, activate emergency shutdown and response |
| Malfunction of a pipeline component during the course of performing a covered task | • Make appropriate notifications<br>AND<br>• If authorized, initiate emergency shutdown/ isolation of pipeline facility and/or component |
| Physical damage of a pipeline facility or component | • Make appropriate notifications |

## PROCEDURE

These procedures are minimum requirements. Some situations may require additional actions to achieve an adequate margin of safety.

This program provides a brief overview of the pipeline and liquid characteristics that may create external or internal corrosion.

## PIPELINE AND LIQUID CHARACTERISTICS

### PIPELINE

The AHFP is constructed with un-insulated coiled tubing supported on vertical support members (VSM). Sub-grade road crossings are routed through casings and none of the pipe surface is exposed to soil or gravel.

### LIQUID

The AHFP carries Ultra Low Sulfur Diesel and other approved products. These products have very low water content. The risk of internal corrosion with this low water content is very small. Because of this low water content, corrosion inhibitor is not utilized in the AHFP.

## INSPECTION

To control corrosion, CPAI performs inspection activities in accordance with the Integrity Management Program (IMP) Inspection Section. A brief summary of techniques is provided in this section.

### PRESSURE TESTS

The AHFP only accommodates maintenance pigs, which are used quarterly to ensure the pipeline is free of solids, deposits and water dropout. Therefore, to satisfy the Integrity Management Program (IMP), ConocoPhillips Company performs hydrostatic testing at least once every 5 years following the initial baseline assessment[1], in accordance with SPC-HP-NS-80002, "Pipeline Hydrostatic Testing Specification", using the product being transported.

### ULTRASONIC OR RADIOGRAPHIC INSPECTIONS

Inspections utilizing Ultrasonic (UT) or Radiographic (RT) techniques are performed at the Corrosion Engineer's discretion to check for the presence of internal pipe wall corrosion. UT and RT are also used to confirm results from other techniques, such as visual inspection, when deemed necessary.

UT and RT are not assessment methods identified within 49 CFR 195.452(j)(5) and therefore, according to 49 CFR 195.452(j)(5)(iv) require a notification be sent

1 In accordance with 195.452(d)(1), the baseline assessment must be completed by March 31, 2008.

to PHMSA 90 days before conducting the assessment. For more information on this requirement refer to the Liquids Management Integrity Program.

### *VISUAL INSPECTIONS*

A visual inspection for external corrosion damage is conducted on any area of the AHFP when repairs are performed on that portion of the line. Visual inspection of internal pipe wall surfaces is conducted whenever internal surfaces are available for inspection.

All road crossings are visually inspected to ensure debris and, subsequently, water are not accumulating in the casing or pipe annulus.

Visual inspection for Atmospheric Corrosion on pipe, flange and valve surfaces is performed on a third of the pipeline every year to ensure the entire pipeline length is inspected every three years not to exceed thirty-nine months.

### *CORROSION COUPONS*

To assist in monitoring internal corrosion potential, coupons are located at the inlet and outlet of the primary pipeline segments. Coupons are removed and evaluated twice per year at an interval not to exceed 7-1/2 months. If coupon corrosion rates exceed three mils per year general or ten mils per year pitting, the cause will be investigated.

## *MITIGATION*

CPAI uses maintenance pigging and cathodic protection to mitigate corrosion as described herein.

### *MAINTENANCE PIGGING*

The AHFP is maintenance pigged quarterly to reduce water dropout and sediment accumulation potential. If there is a need to change this schedule temporarily for operational needs, the Corrosion Engineers are consulted and appropriate approvals secured.

### *CATHODIC PROTECTION*

The majority of the AHFP is supported by an aboveground system composed of vertical and horizontal support members. Exceptions are the Colville River crossing and Road Crossings.

### COLVILLE RIVER CROSSING

At the Colville River crossing, the pipeline transitions below the river within an 18-inch drilled air-annulus casing. Since the line is not buried or submerged by DOT definition, there is no cathodic protection system on the pipeline.

As a best practice, CP has been applied to the casing and a leak detection system is used to confirm its integrity. Should the casing fail, the DOT pipelines would then meet the definition of buried or submerged pipelines and would require CP according to 195.563. APLM-0000-SD-0046, “HDD Cathodic Protection Normal Operating Procedures”, provides a detailed system description, and APLM-0000-SD-0045, “HDD Cathodic Protection System Performance Testing” describes rectifier readings and annual system testing.

### ROAD CROSSINGS

At road crossings, the pipeline is also routed below grade within an air-annulus casing. None of the pipe surface is exposed to soil or gravel. Since the line is not buried or submerged by DOT definition, there is no cathodic protection system on the pipeline.

## REMEDIATION

If inspection techniques indicate either general corrosion or localized pitting has occurred, pipeline remediation is performed in accordance with the Integrity Management Program Remediation Strategy.

## DOCUMENTATION

The CPAI Corrosion Team retains documentation pertaining to corrosion program activities on the SWPL in the North Slope AI Corrosion files or database in accordance with 195.589(c). This includes:

- AHFP inspection reports (including visual, UT, and RT inspection results)
- Pipe strength calculations

- Annual road crossing casing visual inspection results
- Corrosion coupon results.

Cathodic protection, maintenance pigging, and pressure test records are retained in the Alpine SAP Document Management System (DMS) database.

## *REFERENCES*

The listed documents are not by reference part of this procedure. Reference is made only to the paragraph or section listed and not the entire document

### *INDUSTRY STANDARDS*

| | |
|---|---|
| ASME B31.G | Manual for Determining the Remaining Strength of Corroded Pipelines |
| RSTRENG | AGA, Project PR-3-805, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe” |

### *COMPANY REFERENCES*

| | |
|---|---|
| APLM-0000-SD-0045 | HDD Cathodic Protection System Performance Testing |
| APLM-0000-SD-0046 | HDD Cathodic Protection Normal Operating Procedure |

**(End of Document)**

## REVISION / APPROVAL LOG

| Rev. No. | Date | Action | By |
|---|---|---|---|
| 18 | 10/6/2012 | Moved DOT Reference to NSPL 5502<br>Removed TOC<br>Added atmospheric corrosion to Visual Inspections section | Dan Schmidt |
| 19 | 11/5/2012 | Updated OQ 4232 title to Corrosion Control Access Tools<br>Removed table formatting | A. Peltier |
| 20 | 01/29/13 | Renamed OQ 4233.3 to OQ 4233 Pipeline Pigging – Perform | M. Undesser |
| 21 | 11/16/13 | Revised Governing reference to Pressure Testing in Minimum Requirements Table<br>Added OQ 4901 to Operator Qualification | Dan Schmidt |
| 22 | 9/21/14 | Added OQ and AOC information<br>Changed header and footer to current standard | Alpine Pipeline Coordinator |
| 23 | 11/01/16 | Removed 195.569, DOT regulation for crossing debris, clarified visual inspection requirement, changed documentation section. | K. McCullough |
| 24 | 12/26/16 | Formatted to current template | K. McCullough |
| 25 | 7/11/17 | Updated DOT regulation citations covering atmospheric corrosion monitoring and visual inspection requirements. Included the requirement for the 90-day notice to PHMSA prior to using RT and UT to assess external corrosion. | E. Zanto<br>S. Colegrove |

## DOCUMENT SUMMARY

This procedure outlines the corrosion control program used to ensure the mechanical integrity of the Alpine Seawater Pipeline (SWPL). Discussion includes responsibilities, regulatory requirements, external and internal corrosion monitoring and mitigation, and documentation retention.

**NOTE:** The SWPL is not under DOT jurisdiction. ConocoPhillips Alaska, Inc. (CPAI) voluntarily performs corrosion surveillance activities and retains records in accordance with DOT regulations.

## RESPONSIBILITIES

### ALASKA ASSET INTEGRITY (AI)

The Alaska Asset Integrity (AI) Corrosion Team are responsible for developing and implementing this program, which includes monitoring, inspecting and testing, and evaluating and recommending repairs and operating changes. Drawing APLM-00SW-D-08, "Pipeline Specifications", summarizes the key pipe specifications used for the SWPL.

### CORROSION ENGINEER

The Corrosion Engineer is responsible for:

- Evaluating field results to identify corrosion abnormalities that may affect the pipeline's ability to operate at its designed maximum operating pressure (MOP).
- Immediately reporting such abnormalities to the Alpine Operations Superintendent for review, approval, and corrective action, as necessary.

### NORTH SLOPE AI SUPERVISORS

The North Slope AI Supervisors are responsible for:

- Overseeing the SWPL Corrosion Program.

- Making sure inspection, monitoring results, evaluations and repair recommendations are consistent with applicable regulatory or industry code and standard requirements or commitments.
- Making sure results and recommendations are communicated to the Alpine Operations and Maintenance Superintendent for review, approval, and corrective action, as necessary.

### *ALPINE OPERATIONS AND MAINTENANCE SUPERINTENDENT*

The Alpine Operations and Maintenance Superintendent is responsible for:

- Cathodic protection (CP) system maintenance.
- Routine maintenance pigging.
- Responding to corrosion control corrective action recommendations.

## *REGULATORY REQUIREMENTS*

### *DEPARTMENT OF TRANSPORTATION (DOT) JURISDICTION*

- The SWPL is not under DOT jurisdiction. ConocoPhillips Alaska, Inc. (CPAI) voluntarily performs corrosion surveillance activities and retains records in accordance with DOT regulations.

### *STATE OF ALASKA – RIGHT-OF-WAY LEASE AND STIPULATIONS*

Section 14(c) and Exhibit A, Stipulation 1.6.1, of the Alpine Seawater Pipeline, Right-of-Way Lease, ADL 415857, requires a Surveillance and Monitoring Program to detect and abate situations that may endanger health, safety, environment or the integrity of the pipeline system. In addition, Stipulation 3.2.1 requires early detection of corrosion in accordance with the application, state requirements, and 49 CFR 195.

### *MINIMUM REQUIREMENTS*

| Category | Governing Reference | Minimum Frequency | Task |
|---|---|---|---|
| Internal / External Corrosion | 195.452(j)(3)<br>195.452(j)(5)(i)<br>195.579(a)<br>195.583 | Every 2 years [1] | Perform instrumented (smart) pigging |
| External Corrosion | 195.569 | When exposed | Inspect pipe for external condition |

| Category | Governing Reference | Minimum Frequency | Task |
|---|---|---|---|
| External Corrosion | ROW 1.6.1 | Annually | Inspect below grade crossings to ensure free of debris |
| External Corrosion | 195.452(j)(3)<br>195.452(j)(5)(iii)<br>195.583<br>195.588 | Every 3 years | Inspect un-piggable sections of pipe for condition |
| Internal Corrosion | 195.452(j)(5)(iv)<br>195.579(a) | Every 3 years | Inspect un-piggable elevation change elbows for condition and solids build-up |
| Internal Corrosion | 195.579(c) | When open | Inspect for internal condition |
| Internal Corrosion | 195.579(b)(3) | Semi-Annual | Pull corrosion coupons for evaluation |
| Internal Corrosion | 195.579(a) | Monthly | Perform maintenance pigging |
| Cathodic Protection | 195.573(c) [2] | Every 2 months | Confirm and record rectifier readings |
| Cathodic Protection | 195.575 195.577 [2] | Annually | Confirm system functioning (casing isolation) |
| Cathodic Protection | 195.571<br>159.573(a)(1)<br>195.573(e) [2] | Annually | Polarization Decay Testing |
| HDD Thaw Settlement | ROW | Every 4 years [3] | Instrumented (smart) pigging<br>Inertial Navigation (geometry) Pig |

NOTES:

1. 195.452(j)(5)(i) requires inspection intervals not to exceed 5 years. As approved in the SPCS Surveillance and Monitoring Program and as referenced in the Alpine Utility Pipeline *Analysis of Aboveground pipeline and Aboveground River Crossings – Supplemental Information*, submitted to State Pipeline Coordinator in June 2002, corrosion pigging will take place at least every two years.

2. The Alpine carrier pipelines at the Colville River crossing transition below the river within a drilled (air annulus) casing. As such, these pipelines are not buried or submerged by DOT definition and CP of the pipeline is not required. CP was applied to the casing as a best practice and the leak detection system is used to confirm the integrity of the casing. Should the casing fail, the pipelines would meet the definition of buried or submerged pipelines, and would require CP according to §195.563.

3. Incorporated by reference into the Alpine Utility Pipeline Right-of-Way Lease and Stipulations, the Colville River Crossing Design Report, Revision 3, May 1999, requires the gathering of thaw settlement data using smart pigs in 2001, 2003, and 2005, to determine the extent of thaw settlement and evaluate the stress and strain in the pipelines compared against the allowable levels previously established. In 2005, the frequency of smart pig runs must be evaluated and program adjusted as necessary.

# PRECAUTIONS AND LIMITATIONS

## ABNORMAL OPERATING CONDITIONS (AOC)

The following are the AOC that could be encountered while performing this procedure and the appropriate response to make should the AOC be encountered:

| Abnormal Operating Condition | Appropriate Response |
|---|---|
| Leak or unintended release of hydrocarbon from a pipeline component | • Make appropriate notifications<br>AND<br>• If authorized, initiate emergency shutdown/ isolation of pipeline facility and/or component |
| Fire or explosion due to a release of hydrocarbon | • Make appropriate notifications<br>AND<br>• If authorized, activate emergency shutdown and response |
| Malfunction of a pipeline component during the course of performing a covered task | • Make appropriate notifications<br>AND<br>• If authorized, initiate emergency shutdown/ isolation of pipeline facility and/or component |
| Physical damage of a pipeline facility or component | • Make appropriate notifications |

# PROCEDURE

These procedures are minimum requirements. Some situations may require additional actions to achieve an adequate margin of safety.

This program provides a brief overview of the pipeline and liquid characteristics that may create external or internal corrosion.

## PIPELINE AND LIQUID CHARACTERISTICS

### PIPELINE

External corrosion typically is caused by water ingress into the insulation system. Shop-applied insulation is installed with a plastic membrane between the insulation and the metal jacketing, making it waterproof (except at the ends). External corrosion can occur when water penetrates at weld insulation packs, applied in the field after line segment fabrication, or at sites where the shop-applied insulation jacketing has been damaged. The exception is weld packs installed or replaced after 1998, since the newer weld pack design includes a tape wrap to prevent water ingress into the insulation from contacting the pipe.

### *LIQUID*

The SWPL carries 100% seawater treated with Oxygen Scavenging and Corrosion Inhibitor chemicals to reduce the corrosive characteristics of the product. Weekly treatments of Biocide are added to the seawater as per A&OI recommendations.

## *INSPECTION*

To control corrosion, CPAI performs inspection activities in accordance with the Integrity Management Program (IMP) Inspection Section. A brief summary of techniques is provided in this section.

### *INSTRUMENTED (SMART) PIG INSPECTIONS*

An instrumented (smart) pig capable of detecting external corrosion damage is run through the piggable segment of the SWPL. The 12-inch line segment is the only line portion that is piggable.

### *TANGENTIAL RADIOGRAPHIC INSPECTION*

TRT of weld pack locations on the un-piggable sections of the SWPL is performed at least every three years to detect and monitor external corrosion damage. Locations are selected by the Corrosion Engineer and include those with previous problems or damage, saddles, and additional random sites.

### *ULTRASONIC OR RADIOGRAPHIC INSPECTIONS*

Ultrasonic (UT) or radiographic (RT) techniques are used to confirm results from other techniques, such as instrumented (smart) pigging or visual inspection, when deemed necessary. These techniques are also used for the un-piggable pipeline segments at the Corrosion Engineer's discretion to check for internal pipe wall corrosion.

### VISUAL INSPECTIONS

Visual inspections of actual pipe wall surfaces are conducted when insulation is removed for external inspections or when internal surfaces are exposed.

All road crossings are visually inspected to ensure debris and, subsequently, water are not accumulating in the casing or pipe annulus.

Visually inspect for Atmospheric Corrosion on pipe, flange and valve surfaces outside of modules where exposed. Inspection intervals are once every three years not to exceed thirty-nine months.

### CORROSION COUPONS

To assist in monitoring internal corrosion potential, coupons are located at the inlet and outlet of the primary pipeline segments. Coupons are removed and evaluated twice per year at an interval not to exceed 7-1/2 months. If coupon corrosion rates exceed three mils per year general or ten mils per year pitting, the cause will be investigated.

## MITIGATION

CPAI uses maintenance pigging and cathodic protection to mitigate corrosion as described herein.

### MAINTENANCE PIGGING

The SWPL is maintenance pigged tri-weekly to remove any accumulations of sediment where corrosion may mitigate. If there is a need to change this schedule temporarily for operational needs, the Corrosion Engineers are consulted and appropriate approvals secured.

### CATHODIC PROTECTION

The majority of the SWPL is supported by an aboveground system composed of vertical and horizontal support members. Exceptions are the Colville River crossing and Road Crossings.

### COLVILLE RIVER CROSSING

At the Colville River crossing, the pipeline transitions below the river within an 18-inch drilled air-annulus casing. Since the line is not buried or submerged by DOT definition, there is no cathodic protection system on the pipeline.

As a best practice, CP has been applied to the casing and a leak detection system is used to confirm its integrity. Should the casing fail, the DOT pipelines would then meet the definition of buried or submerged pipelines and would require CP according to 195.563. APLM-0000-SW-0046, “HDD Cathodic Protection – Normal Operating Procedures”, provides a detailed system description, and APLM-0000-SW-0045, “HDD Cathodic Protection System – Performance Testing” describes rectifier readings and annual system testing.

### *ROAD CROSSINGS*

At road crossings, the pipeline is also routed below grade within an air-annulus casing. None of the pipe surface is exposed to soil or gravel. Since the line is not buried or submerged by DOT definition, there is no cathodic protection system on the pipeline.

## *REMEDIATION*

If inspection techniques indicate either general corrosion or localized pitting has occurred, pipeline remediation is performed in accordance with the Integrity Management Program Remediation Strategy.

## *DOCUMENTATION*

The CPAI Corrosion Team retains documentation pertaining to corrosion program activities on the SWPL in the North Slope AI Corrosion files or database in accordance with 195.589( c). This includes:

- SWPL inspection reports (including visual, TRT, UT, and RT inspection results)
- Pipe strength calculations
- Instrumented (smart) pig results
- Annual road crossing casing visual inspection results

- Corrosion coupon results.

Cathodic protection and maintenance pigging records are retained in the Alpine SAP Document Management System (DMS) database.

## REFERENCES

The listed documents are not by reference part of this procedure. Reference is made only to the paragraph or section listed and not the entire document

### INDUSTRY STANDARDS

| | |
|---|---|
| ASME B31.G | Manual for Determining the Remaining Strength of Corroded Pipelines |
| RSTRENG | AGA, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" |

### COMPANY REFERENCES

| | |
|---|---|
| APLM-0000-SW-0046 | HDD Cathodic Protection – Normal Operating Procedure |
| APLM-0000-SW-0045 | HDD Cathodic Protection System – Performance Testing |

**(End of Document)**

## *REVISION / APPROVAL LOG*

| Rev. No. | Date | Action | By |
|---|---|---|---|
| 8 | April 27, 2011 | Converted to new format | Alpine Pipeline Coordinator |
| 9 | May 13, 2011 | - Revise 4232 and 4233.3 AOCs to conform with OQ Program Appendix A.<br>- Change HDD Thaw Settlement Geometry Pig frequency to every 4 years. | Gary Haught |
| 10 | June12, 2012 | Replaced OQ 4221 and 4231 with new OQ 4620 | M. Undesser |
| 11 | October 7, 2012 | Moved DOT References to NSPL 5502<br>Removed TOC<br>Added atmospheric corrosion to Visual Inspections section | Dan Schmidt |
| 12 | November 5, 2012 | Updated OQ 4232 title to Corrosion Control Access Tools<br>Removed table formatting | A. Peltier |
| 13 | January 29, 2013 | Renamed OQ 4233.3 to OQ 4233 Pipeline Pigging – Perform | M. Undesser |
| 14 | 11/16/13 | Added Corrosion Inhibitor and Biocide discussion to Section 3.1 | Dan Schmidt |
| 15 | 10/14/2014 | Changed header and footer to current standard. | Alpine Pipeline Coordinator |
| 16 | 11/22/2016 | Changes responsibility from CPF3 Superintendent to Alpine and removed OQ references, and made some title changes. | Alpine Operations Compliance Specialist |

# ATTACHMENT 5

a. Quality Assurance Program

b. Design Criteria/As-builts - Information redacted; see Confidential Version

c. Surveillance and Monitoring

- Surveillance and Monitoring Change Justification
- Surveillance and Monitoring Program
- 2017 Annual Mechanical Ground Inspection Results
- Alpine Oil Pipeline In-Line Inspection Results
- Alpine Utility Pipeline In-Line Inspection Results

d. **Environmental Compliance**

- 2017 Alpine Pipeline Hydrology Monitoring - Information redacted; see Confidential Version
- **Summary of Spectacled Eider Observations Along the Alpine Pipelines, 1993-2014**

e. Geo-spatial Data - Information redacted; see Confidential Version

# SUMMARY OF SPECTACLED EIDER OBSERVATIONS ALONG THE ALPINE PIPELINES, 1993–2014

Prepared for

**ConocoPhillips Alaska, Inc.**
P.O. Box 100360
Anchorage, AK 99510

Prepared by

Charles B. Johnson
and
Dorte Dissing

**ABR, Inc.—Environmental Research & Services**
P.O. Box 80410
Fairbanks, AK 99708

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## INTRODUCTION

Since 2004, ABR, Inc., has conducted surveys for Spectacled Eiders under contract to ConocoPhillips Alaska, Inc., (CPAI) along the Alpine Pipelines between the Kuparuk and Alpine oilfields. Four (4) CPAI pipelines are regulated by the U.S. Department of Transportation (USDOT) under the Pipeline Safety Act (49 CFR 195.6): the Oliktok Pipeline, Kuparuk Pipeline, Alpine Oil Pipeline, and Alpine Arctic Heating Fuel Pipeline. CPAI instituted surveys in 2004 for threatened eiders within a corridor along the USDOT Alpine Oil and the Arctic Heating Fuel pipelines (hereafter, the Alpine Pipelines) between the CD-1 processing facility at Alpine on the Colville River delta and Central Processing Facility 2 (CPF-2) in the Kuparuk oilfield (Figure 1). The other USDOT regulated pipelines in the Greater Kuparuk Area (GKA, which encompasses the Kuparuk oilfield) have been included in annual aerial surveys for pre-nesting eiders since 1993 (Stickney et al. 2014), but only to the eastern boundary of the GKA unit.

Under 49 CFR 195.6, the Pipeline and Hazardous Materials Safety Administration of USDOT is required to identify and protect Unusually Sensitive Areas (USAs) where “drinking water or ecological resources are especially sensitive to environmental damage from a hazardous liquid pipeline release”. Ecological resources for which USAs can be delineated include areas containing threatened or endangered species with a limited range, as well as other important ecological communities such as waterbird aggregation areas. Oil and gas pipelines within USAs are required to have Pipeline Integrity Management Plans that are intended to protect the resources of USAs from spills of hazardous liquids. The northern portion of the Arctic Coastal Plain of Alaska was identified as an USA because it is within the breeding range of the Spectacled Eider (*Somateria fischeri*), a primarily arctic breeding sea duck, which was listed as threatened in 1993 (58 FR 27474) under the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 et seq.). Another sea duck, the Steller's Eider (*Polysticta stelleri*), was listed as threatened in 1997 (62 FR 31748–31757), but it breeds mainly in western and northwestern Alaska and is uncommon east of Point Barrow (Johnson and Herter 1989, Quakenbush et al. 2002). Less than 10 observations of Steller’s Eiders have accumulated over the last 20 years in areas surveyed for pre-nesting eiders in the GKA and Colville River delta, and no evidence of breeding has been documented in this region. No areas of critical habitat have been designated on the Arctic Coastal Plain for either of these threatened eiders. Critical habitat for the Spectacled Eider comprises 4 areas: coastal terrestrial zones of the Yukon-Kuskokwim Delta, a portion of Norton Sound, Ledyard Bay in the Chukchi Sea, and the wintering area on the south side of Saint Lawrence Island in the Bering Sea (66 FR 9146–9185). Critical habitat for the Steller's Eider also includes a coastal area of the Yukon-Kuskokwim Delta and marine zone of Kuskokwim Bay, as well as coastal waters of the Seal Islands and Nelson and Izembek lagoons along the Alaska Peninsula (66 FR 8850–8884).

The purpose of this report is to summarize what is known about Spectacled and Steller's eider occurrence and distribution in the area of the Alpine Pipelines between CPF-2 in the GKA and CD-1 in Alpine. We summarize data collected on the Colville Delta and Alpine Transportation Corridor study areas (Smith et al. 1994; Johnson 1995; Johnson et al. 1996, 1997, 1998, 1999, 2000, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, 2013, 2014, 2015; Burgess et al. 2000, 2002, 2003) , the GKA (Anderson and Cooper 1994; Anderson et al. 1995, 1996, 1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004, 2005a, 2005b, 2007, 2008, 2009; Stickney et al. 2010, 2011, 2012, 2013, 2014, in prep.), and the Alpine Pipelines surveys (Anderson and Shook 2004; Anderson 2005, 2006, 2007, 2008, 2009; Stickney 2010, 2011, 2011, 2012, 2014a, 2014b).

## STUDY AREA

The Alpine Pipelines traverse an east–west corridor between the CPF-2 in the GKA on the east to the horizontal directional drilling pipeline crossing (HDD) on the Colville River in the west (Figure 1). From HDD, the Alpine Pipelines turn northwesterly to the processing facility on CD-1 in the Alpine oilfield. The Alpine Pipelines are located on the Arctic Coastal Plain of Alaska in an area dominated by habitats created by the thaw-lake cycle, fluvial processes from the Kuparuk and Colville rivers, and coastal processes of flooding, erosion, and sediment deposition. The representative vegetation and landforms are discussed in Roth et al. (2007) and Roth and Loomis (2008) for most of the GKA and in Jorgenson et al. (1997) for the Colville River delta and the Alpine Transportation Corridor study area (which encompasses most of the route of the Alpine Pipelines).

## METHODS

One aerial survey was conducted each year from 2004 to 2014 during 12–18 June for breeding pairs of eiders along the Alpine Pipelines between CPF-2 in the GKA and CD-1 at Alpine on the Colville River delta (Figure 1). Surveys were flown during the pre-nesting period, when male eiders (the more conspicuous of the sexes when in breeding plumage) are still on the breeding grounds. The survey area was a strip 400 m (~0.25 miles) wide on each side of the pipelines for 100% coverage of a 800 m (~0.5 miles) strip. The other USDOT pipelines in the GKA were surveyed for Spectacled Eiders 8–18 June during the regional aerial survey of the GKA by flying east–west transects spaced 800 m apart, providing 50% coverage of the Greater Kuparuk study area (Table 1). The Colville Delta study area also was surveyed for eiders over the same dates as the Greater Kuparuk study area but at 100% coverage (transects spaced at 400 m intervals, except in 1993, when transects were spaced at 800 m intervals achieving 50% coverage). Partial coverage of the pipeline route was achieved by various eider surveys in years before 2004. Beginning in 1993, pre-nesting aerial surveys were flown 8–19 June in east–west transects over the Greater Kuparuk and Colville Delta study areas (Table 1), thereby covering other USDOT regulated CPAI pipelines. In 1993 and 1995–1997, the Alpine Transportation Corridor, which included multiple potential routes of the Alpine Pipelines, was surveyed in support of construction permit applications. In 1994, a survey was flown only in the Colville Delta study area, and in 1999, a survey was flown only in the Greater Kuparuk study area. In 1998, and 2000–2003, surveys were flown in both the Colville Delta and Greater Kuparuk study areas, but the area between these 2 study areas was not surveyed.

The procedures for the aerial survey of the Alpine Pipelines were similar to those used since 1993 (Anderson and Cooper 1994, Smith et al. 1994) and employed 2 observers (in addition to the pilot) in a fixed-wing aircraft (Cessna 185 or 206). During the survey, the pilot navigated the airplane following the pipelines on transects 400 m apart, using a global positioning system (GPS) receiver and photomosaic maps of the area, as well as visual reference to the pipelines. Flight altitude was 30–50 m (98–164 feet) above ground level and flight speed was approximately 145 km/h (90 mph). Using a tape or digital recorder, each observer noted the species of eider, the number of each sex, the number of identifiable pairs, the side (north or south) of the pipelines, and whether the birds were flying or on the ground. Each observer also marked all eider locations on photomosaic maps of the survey area scaled to 1:63,360. All observations were added to a GIS database. Only locations of eiders seen on the ground are reported here, as the flying birds could not be assigned to a specific location.

When Spectacled Eiders were recorded on the Alpine Pipelines survey, the study protocol required a nest search be conducted in the location of the observations. Three or more people would start at the coordinate of the pre-nesting location searching at least a 400 m radius around the location including the shorelines and islands of all nearby waterbodies and all wet meadow habitats, which are preferred nesting areas for Spectacled Eiders. In addition to nest searches prompted by observation of pre-nesting Spectacled Eiders within 400 m of the Alpine Pipelines, nest searches were conducted during 3 years in the CD-4 area prior to construction of the CD-4 drill site (Burgess et al. 2000, 2002, 2003) and during approximately 20 years in the CPF-2 area as part of the GKA avian studies (Stickney et al., in prep.).

## RESULTS

Four species of eiders occur on the Arctic Coastal Plain. No observation of Steller's Eiders or Common Eiders (*Somateria mollissima*) have been recorded in the Alpine Pipelines vicinity; Spectacled Eiders are observed sporadically, whereas King Eiders (*Somateria spectablilis*), which are neither threatened nor endangered, are common and frequently observed (ABR, unpubl. data).

Spectacled Eiders have been recorded in 5 of the 21 years (24%) during which surveys have covered portions of the Alpine Pipelines survey area (the Alpine Pipelines survey area is the area within 400 m of the current Alpine Pipelines location; Figure 1, Table 1). Spectacled Eiders were observed in the Alpine Pipelines survey area prior to construction of the pipelines in 1993, 1997, and 1998 (Figure 2, Table 2). After surveys specifically for the Alpine Pipelines commenced in 2004, Spectacled Eiders were recorded in only 2 years (18% of the 11 years surveys were conducted; Figure 3, Table 2).

Six groups of Spectacled Eiders were observed within 400 m of the Alpine Pipelines in 21 years of surveys (Table 2). Sixteen indicated total birds were recorded, with 14 birds actually observed during surveys. Indicated birds is a standardized method of counting ducks, which doubles the number of males (with exceptions for mixed sex groups) to account for the number of females, which are frequently undercounted on aerial surveys because of their drab plumage (USFWS 1987). Less than 1 Spectacled Eider was observed on average each year (mean = 0.64 observed or 0.73 indicated total, $n = 21$ years). Most records are from the CPF-2 area between approximately DS-2M to CPF-2 (Figures 2 and 3). Only 2 records of pre-nesting Spectacled Eiders have occurred during the Alpine Pipelines surveys, 1 pair near DS-2H in 2006 and 1 group of 3 males and 1 female mid-way between DS-2M and HDD in 2007 (Figure 3).

Three Spectacled Eider nests have been found within 400 m of the Alpine Pipelines, but only 1 nest occurred during years in which the Alpine Pipelines surveys were conducted (Figure 4). In 1998, a Spectacled Eider nest was found 355 m from the future pipelines location near CPF-2 in the GKA (Anderson et al. 1999). One nest was found in 2000 in the Colville Delta study area 182 m from the pipelines during nest searches prior to construction of CD-4 (Burgess et al. 2000). The most recent nest was found in 2013 at 235 m from the pipelines near CPF-2 in the GKA (Stickney et al. 2014). A nest search was conducted in 2007, where 3 male and 1 female Spectacled Eiders were detected on the pre-nesting aerial survey mid-way along the Alpine Pipelines (Figures 3 and 4), but no nests were found. Several depredated eider eggs belonging either to King or Spectacled eiders (eggs of the 2 species are visually indistinguishable) were found near that location and both King and Spectacled eiders were observed in the area; however, no nests were discovered.

## DISCUSSION

The Alpine Pipelines traverse an area supporting low densities of Spectacled Eiders (mean annual density = 0.02 indicated birds/km², SE = 0.01, $n = 21$ years). Records of pre-nesting Spectacled Eiders within the 400 m Alpine Pipelines survey area have been sporadic; Spectacled Eiders were recorded in only 5 of 21 years. We caution that the Alpine Pipelines were surveyed in their entirety only for the last 11 of those years, so it is possible there were Spectacled Eiders in the unsurveyed portions of the Alpine Pipelines prior to 2004. We also caution that lack of observations on a single survey does not prove absence in any year, because pre-nesting eiders are mobile and often not yet settled into final nesting locations. Nonetheless, Spectacled Eiders were observed in only18% of the years the pipelines were completely surveyed and averaged <1 bird/year in the pipeline survey area.

Another data source illustrates the distribution of Spectacled Eiders in the Alpine Pipelines area, and confirms the low numbers observed during pre-nesting surveys. U.S. Fish and Wildlife Service (USFWS) flies annual surveys, at low coverage (2–8%), across the entire Arctic Coastal Plain in mid-June each year and alternates transects annually that are repeated in 4-year cycles (Stehn et al. 2013). The last complete cycle was flown in 2009–2012 and was portrayed in the form of density polygons of pre-nesting Spectacled Eiders (Figure 5). Density polygons provide a way to visualize a smoothed relative density distribution. The majority (72% of survey area) of the Alpine Pipelines route is in the lowest density category (0–0.028 indicated birds/km$^2$). Higher density polygons are crossed by the Alpine Pipelines near CPF-2 in the GKA (>0.028–0.111 indicated birds/km$^2$) and on the Colville River delta (>0.028–0.425 indicated birds/km$^2$), where some of the highest densities occur. Twenty-eight percent of the survey area is in the 4 highest density polygons. The distribution of pre-nesting locations from ABR aerial surveys (Figures 2 and 3) generally agrees with the density distribution estimated from USFWS surveys (Figure 5): the highest densities along the Alpine Pipelines occur at the eastern and western extents of the pipelines survey area, in the CPF-2 area and the Colville River delta, respectively.

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Table 1. Area that was surveyed each year for pre-nesting Spectacled Eiders in the Alpine Pipelines survey area, 1993–2014. Values for 1993–2003 represent the portion of the Alpine Pipelines survey area that was covered by pre-nesting eider surveys in 3 separate study areas in those years.

| Study Area | Year | Coverage (%) | Surveyed Area ($km^2$) |
|---|---|---|---|
| Alpine Pipelines Survey Area[a] | 2004–2011 | 100 | 44.28 |
| | 2012 | 100 | 88.98[b] |
| | 2013–2014 | 100 | 44.28 |
| Pre-2004 Colville Delta study area | 1993 | 50 | 6.54 |
| | 1994 | 100 | 13.08 |
| | 1995–1997 | 100 | 13.08 |
| | 1999 | – | – |
| | 1998, 2000–2003 | 100 | 13.08 |
| Pre-2004 Greater Kuparuk study area | 1993 | 50 | 8.52 |
| | 1994 | – | – |
| | 1995–1997 | 50 | 14.0 |
| | 1999 | 50 | 8.52 |
| | 1998, 2000–2003 | 50 | 8.52 |
| Pre-2004 Transportation Corridor study area | 1993 | 50 | 7.08 |
| | 1995–1997 | 100 | 14.16 |

[a] Total area surveyed at 100% coverage. See Figure 1 for map of study areas
[b] Survey area doubled in 2012 to 800 m on each side of the pipelines

Table 2. Spectacled Eider numbers and densities, and area surveyed on pre-nesting aerial surveys within 400 m of the Alpine Pipelines, Alaska, 1993–2014. See Table 1 and Figures 2 and 3 for areas surveyed.

| Year | Number of Eiders | Indicated Total[a] | Number of Groups | Indicated Total Density[a] | Area Surveyed ($km^2$)[b] |
|---|---|---|---|---|---|
| 1993 | 2 | 2 | 1 | 0.09 | 22.14 |
| 1994 | 0 | 0 | 0 | 0 | 13.08 |
| 1995 | 0 | 0 | 0 | 0 | 41.23 |
| 1996 | 0 | 0 | 0 | 0 | 41.23 |
| 1997 | 4 | 4 | 2 | 0.10 | 41.23 |
| 1998 | 2 | 2 | 1 | 0.09 | 21.6 |
| 1999 | 0 | 0 | 0 | 0 | 8.52 |
| 2000 | 0 | 0 | 0 | 0 | 21.6 |
| 2001 | 0 | 0 | 0 | 0 | 21.6 |
| 2002 | 0 | 0 | 0 | 0 | 21.6 |
| 2003 | 0 | 0 | 0 | 0 | 21.6 |
| 2004 | 0 | 0 | 0 | 0 | 44.28 |
| 2005 | 0 | 0 | 0 | 0 | 44.28 |
| 2006 | 2 | 2 | 1 | 0.05 | 44.28 |
| 2007 | 4 | 6 | 1 | 0.14 | 44.28 |
| 2008 | 0 | 0 | 0 | 0 | 44.28 |
| 2009 | 0 | 0 | 0 | 0 | 44.28 |
| 2010 | 0 | 0 | 0 | 0 | 44.28 |
| 2011 | 0 | 0 | 0 | 0 | 44.28 |
| 2012[c] | 0 | 0 | 0 | 0 | 88.98 |
| 2013 | 0 | 0 | 0 | 0 | 44.28 |
| 2014 | 0 | 0 | 0 | 0 | 44.28 |
| Total | 14 | 16 | 6 | | |
| Mean | 0.64 | 0.73 | 0.27 | 0.02 | 34.20 |
| SE | 0.28 | 0.34 | 0.12 | 0.01 | 2.76 |
| *n* | 21 | 21 | 21 | 21 | 21 |

[a] Indicated total = (no. of males) × 2, except when flocks of mixed sex occurred (more than 5 birds that cannot be separated into breeding pairs), and counted as the number of birds in the flock (USFWS 1987a)

[b] Area surveyed within Alpine Pipelines survey area varied from 44.28 km² (400 m each side of pipelines) due to the following survey changes: 50% coverage in 1993, no survey in the Greater Kuparuk study area in 1994, no survey in the Colville Delta study area in 1999, 50% coverage in the Greater Kuparuk study area in 1995–2003, and no surveys between Greater Kuparuk and the Colville Delta study areas in 1998–2003

[c] Survey area included 800 m on each side of pipeline,1,600 m total width; 1 pair of Spectacled Eiders was recorded 497 m from pipelines

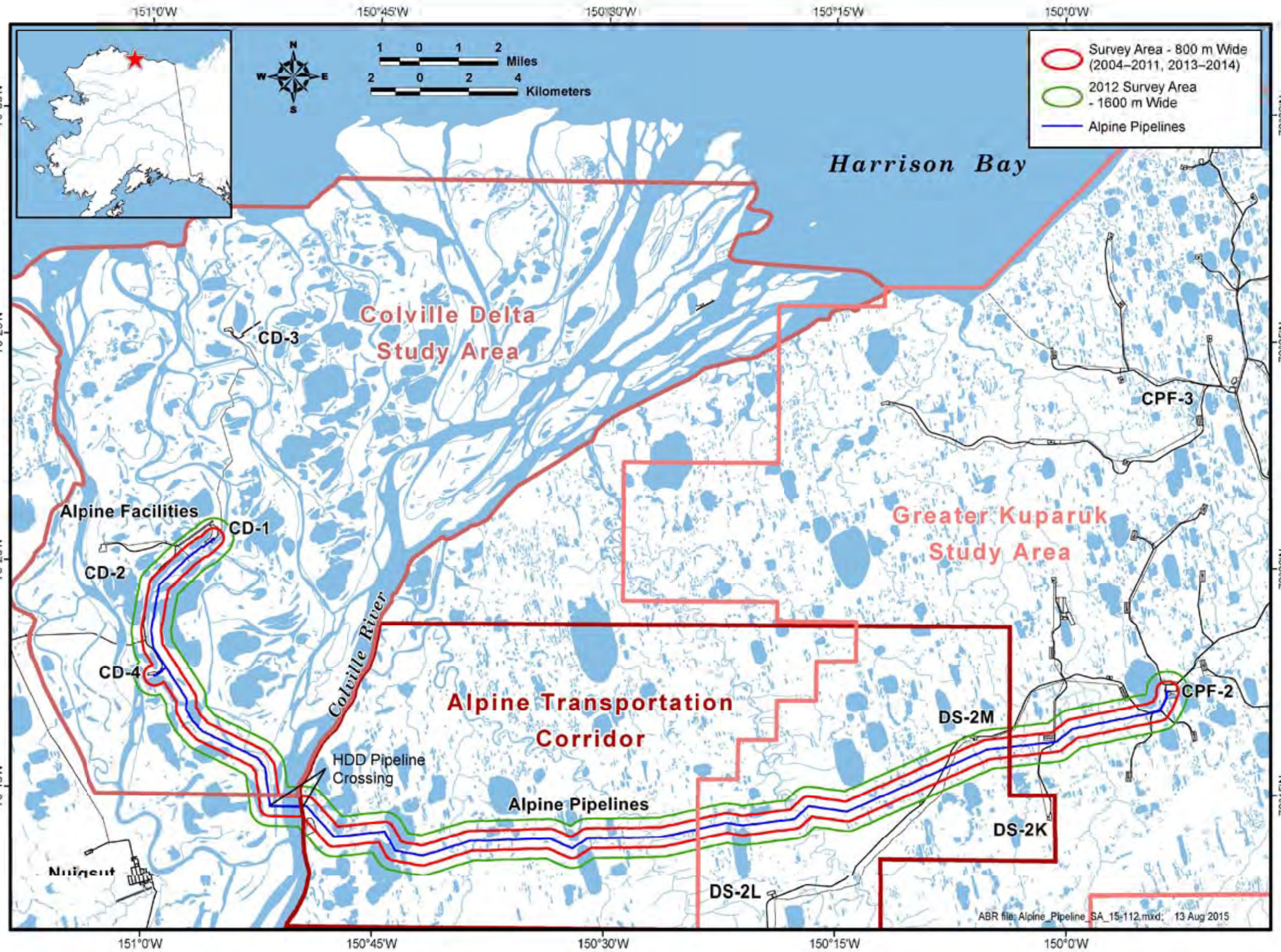


Figure 1. Location of the Alpine Pipelines survey area between the Kuparuk and Alpine oilfields, Alaska, 2004–2014. The survey area was 800 m wide (400 m on each side of the pipelines) except in 2012 when it was 1,600 m wide (800 m on each side of the pipelines). Boundaries of the Colville Delta, Greater Kuparuk, and Alpine Transportation Corridor study areas varied among years.

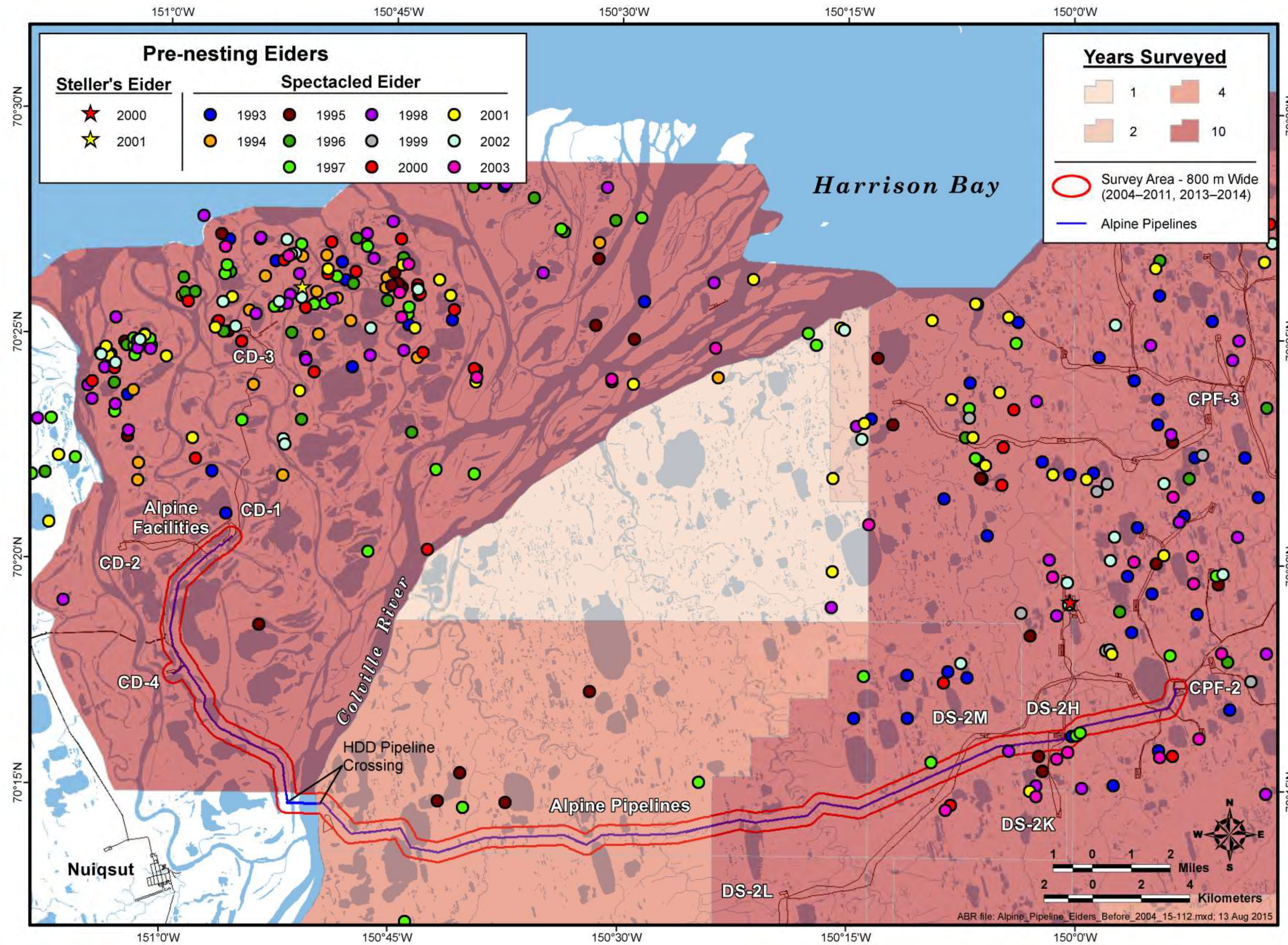


Figure 2. Pre-nesting locations of Spectacled and Steller's eiders in the Alpine Pipelines region from studies prior to the Alpine Pipeline surveys, Alaska, 1993–2003. The Colville Delta study area was surveyed in 1993–1998 and 2000–2003; the Greater Kuparuk study area was surveyed in 1993 and 1995–2003; and the Alpine Transportation Corridor study area was surveyed in 1993 and 1995–1997. Survey coverage was 100% in the Colville Delta and Alpine Transportation Corridor study areas (except 1993 was 50%) and survey coverage was 50% in the Greater Kuparuk study area. See Table 1.

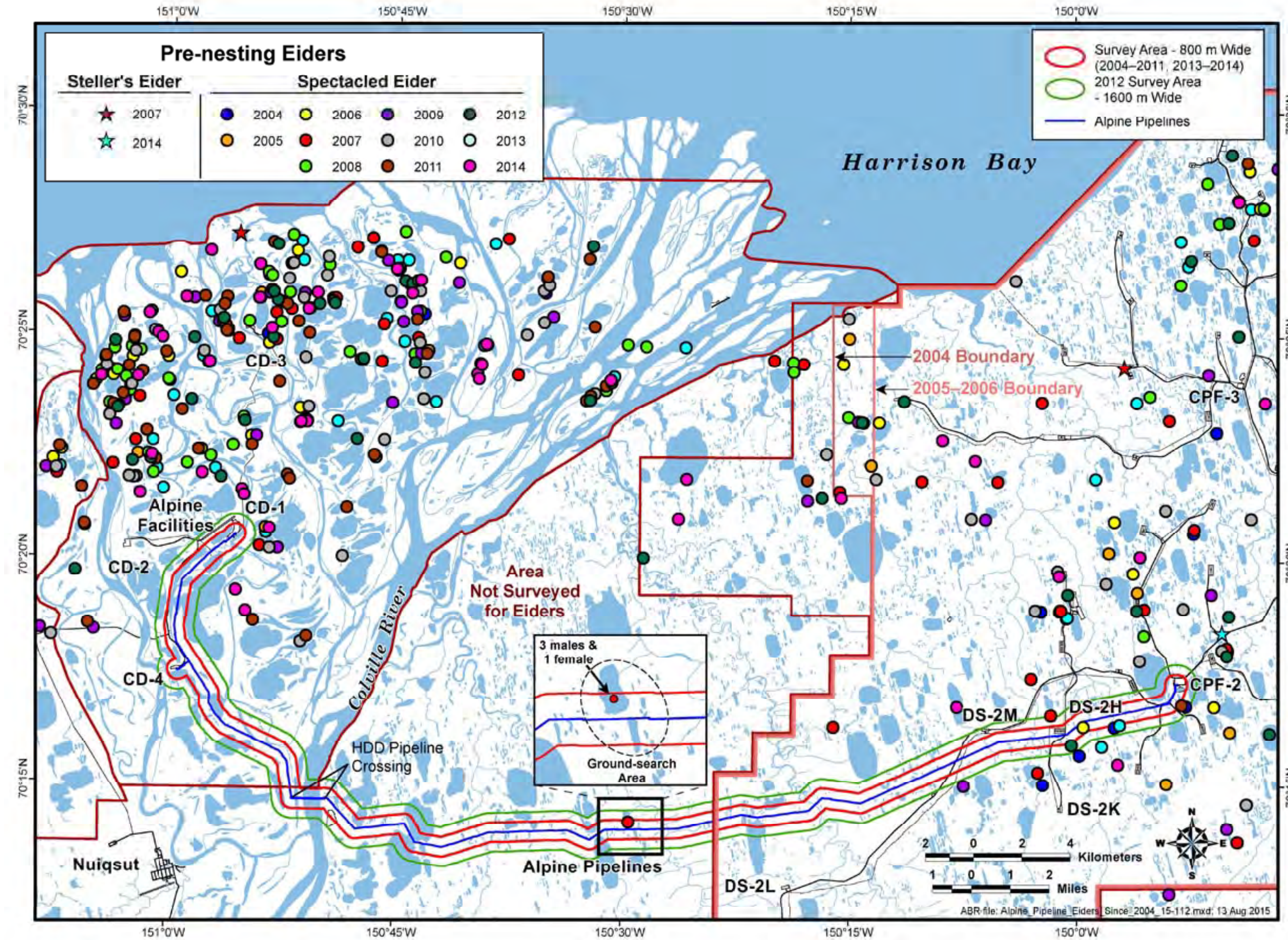


Figure 3. Pre-nesting locations of Spectacled and Steller's eiders during Alpine Pipelines surveys, Alaska, 2004–2014. Survey coverage was 100% in the Alpine Pipelines survey area and in the Colville Delta study area; survey coverage was 50% in the portion of Greater Kuparuk study area outside the Alpine Pipelines survey area. The 1,600 m wide corridor was surveyed in 2012 only. See Table 1.

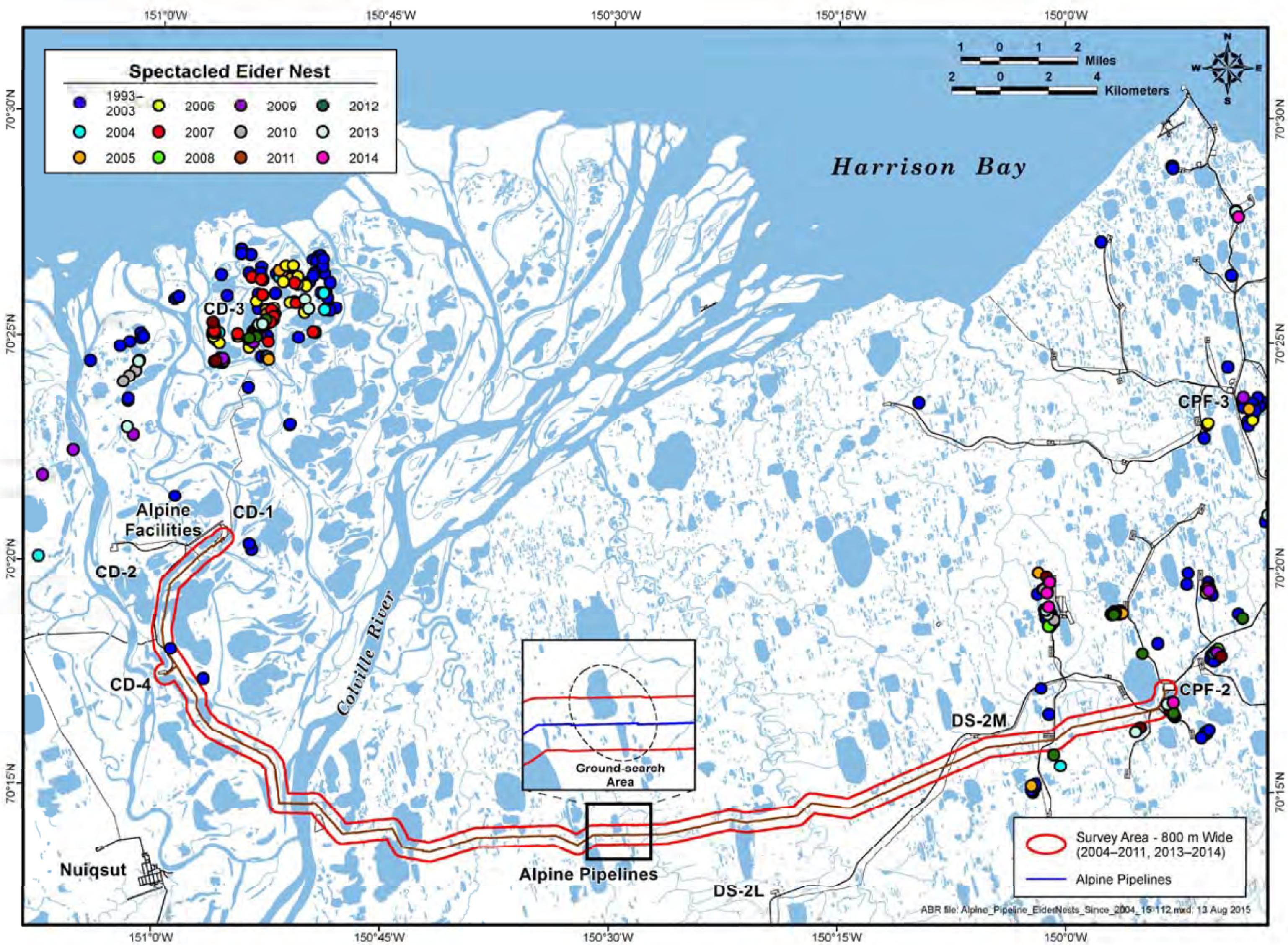


Figure 4. Nesting locations of Spectacled Eiders in the Alpine Pipelines survey area, and in the Colville Delta and Greater Kuparuk study areas, Alaska, 1993–2014. Nest searches were concentrated at CD-3, along ice roads from CD-3 to CD-2, and at various locations along the road system in the Greater Kuparuk study area where pre-nesting Spectacled Eiders were observed or where nests from previous years had been recorded. The ground search area along the pipelines is where 3 males and 1 female Spectacled Eider were seen on the pre-nesting survey in 2007, but no nests were found.

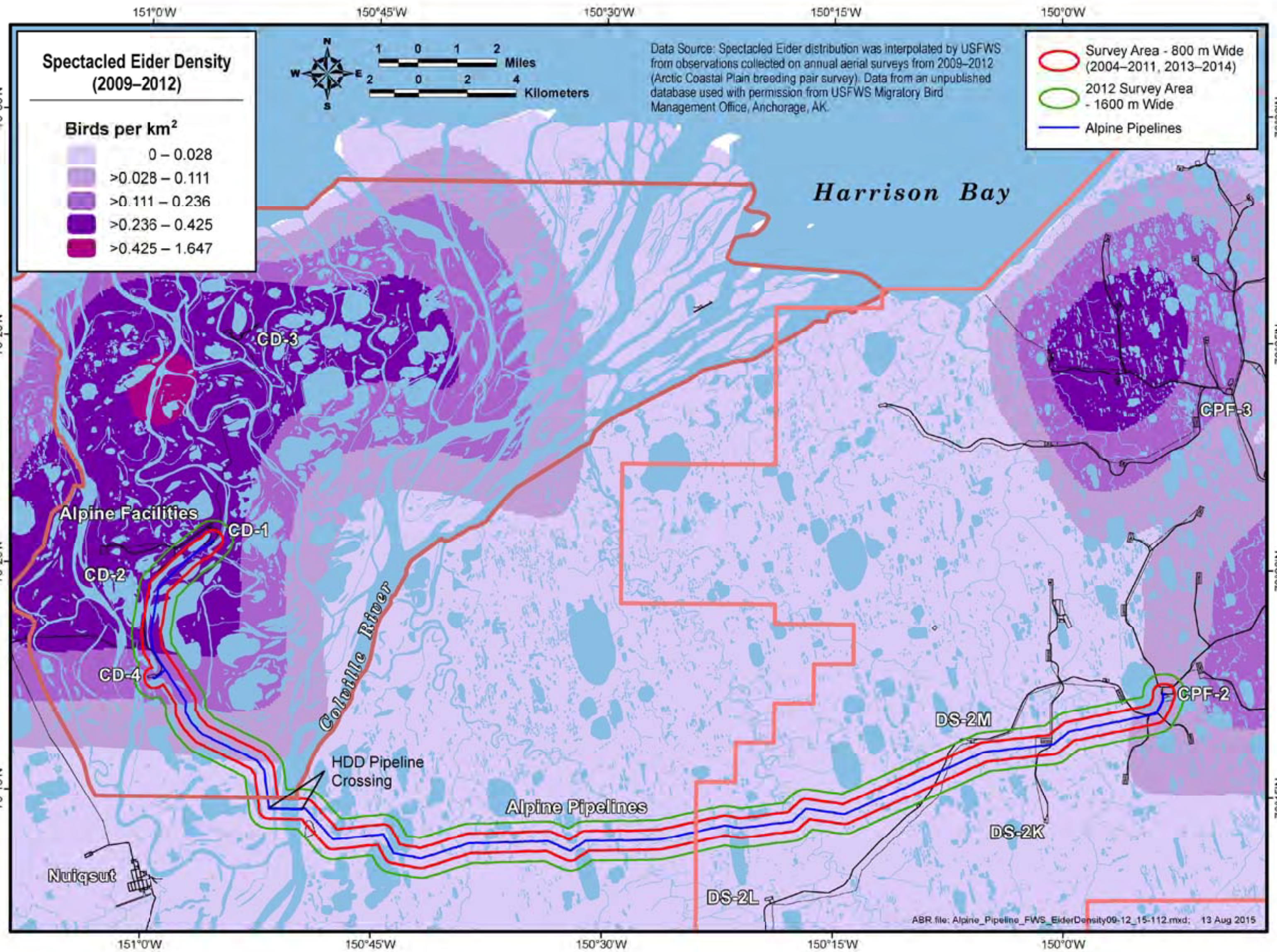


Figure 5. Density distribution of pre-nesting Spectacled Eiders from U.S. Fish and Wildlife Service aerial surveys, Alpine Pipelines area, Alaska, 2009–2012.

# ATTACHMENT 6

a. Alpine Utility Pipeline Amendment Instrument

# ATTACHMENT 6

## a. Alpine Utility Pipeline Amendment Instrument

**AMENDMENT OF RIGHT-OF-WAY GRANT FOR THE ALPINE UTILITY PIPELINE (ADL 415857)**

This **AMENDMENT** is made, entered into, and becomes effective this ____________ day of ________________, 2018 by and between the State of Alaska acting through the Commissioner of Natural Resources or designee, whose mailing address is 411 West 4tth Avenue, Suite 2C, Anchorage, AK 99501-2343, and ConocoPhillips Company (hereinafter referred to as COMPANY), whose mailing address is ConocoPhillips Company, PO Box 100360, Anchorage, Alaska 99510-0360.

This agreement, hereinafter referred to as AMENDMENT, amends the ALPINE UTILITY PIPELINE RIGHT-OF-WAY GRANT as recorded in the Barrow Recording District on January 28, 1999 in Book 104, Pages 753-812.

**WHEREAS**, the COMPANY has requested that Section 2.c. of the existing ALPINE UTILITY PIPELINE RIGHT-OF-WAY GRANT with an effective date of January 6, 1999 be amended to reflect a renewal term for up to thirty years in conformance with AS 38.35.110(a), as amended pursuant to Section 5, Ch. 18, SLA 2001; and

**WHEREAS**, Section 2.c. of the existing ALPINE UTIILTY PIPELINE RIGHT-OF-WAY GRANT reads as follows:

> 2.c. The Commissioner shall, upon request of the Grantee, renew this Grant for additional periods of up to ten years each, so long as the Grantee is in commercial operation and the Grantee is in full compliance with all the terms of this Grant and all state, federal, and local laws including but not limited to state law pertaining to regulation and taxation of the Pipeline System. The Grantee shall give notice of its intent to seek renewal of this Grant no later than six months before expiration.

NOW, therefore, the parties agree that the ALPINE UTILITY PIPELINE RIGHT-OF-WAY GRANT is amended as follows:

Section 2.c. is hereby repealed in its entirety and replaced with the following:

> 2.c. The Commissioner shall, upon request of the Grantee, renew this Grant for additional periods of up to thirty years each, so long as the Grantee is in commercial operation and the Grantee is in full compliance with all the terms of this Grant and all state, federal, and local laws including but not limited to state law pertaining to regulation and taxation of the Pipeline System. The Grantee shall give notice of its intent to seek renewal of this Grant no later than six months before expiration.

Except as expressly amended hereby all terms, covenants and conditions of the ALPINE UTILITY PIPELINE RIGHT-OF-WAY GRANT shall remain in full force and effect.

**IN WITNESS WHEREOF**, the parties have executed this AMENDMENT as the date first above written.

**GRANTEE:** **ConocoPhillips Company**

By: ____________________________________________
Printed name: ____________________________________
Title: ___________________________________________

**LESSOR:** **State of Alaska**

By: ____________________________________________
Printed name: ____________________________________
Title: ___________________________________________

State of Alaska
Third Judicial District

Subscribed and sworn to before me this _____ day of _____________, 20___, at Anchorage Alaska, by _____________________ the ____________________________ of the ConocoPhillips Company.

________________________________
Notary Public in and for Alaska.
My Commission expires: __________

State of Alaska
Third Judicial District

Subscribed and sworn to before me this _____ day of _____________, 20___, at Anchorage Alaska, by _____________________ the _____________________________ on behalf of the State of Alaska.

________________________________
Notary Public in and for Alaska.
My Commission expires: __________