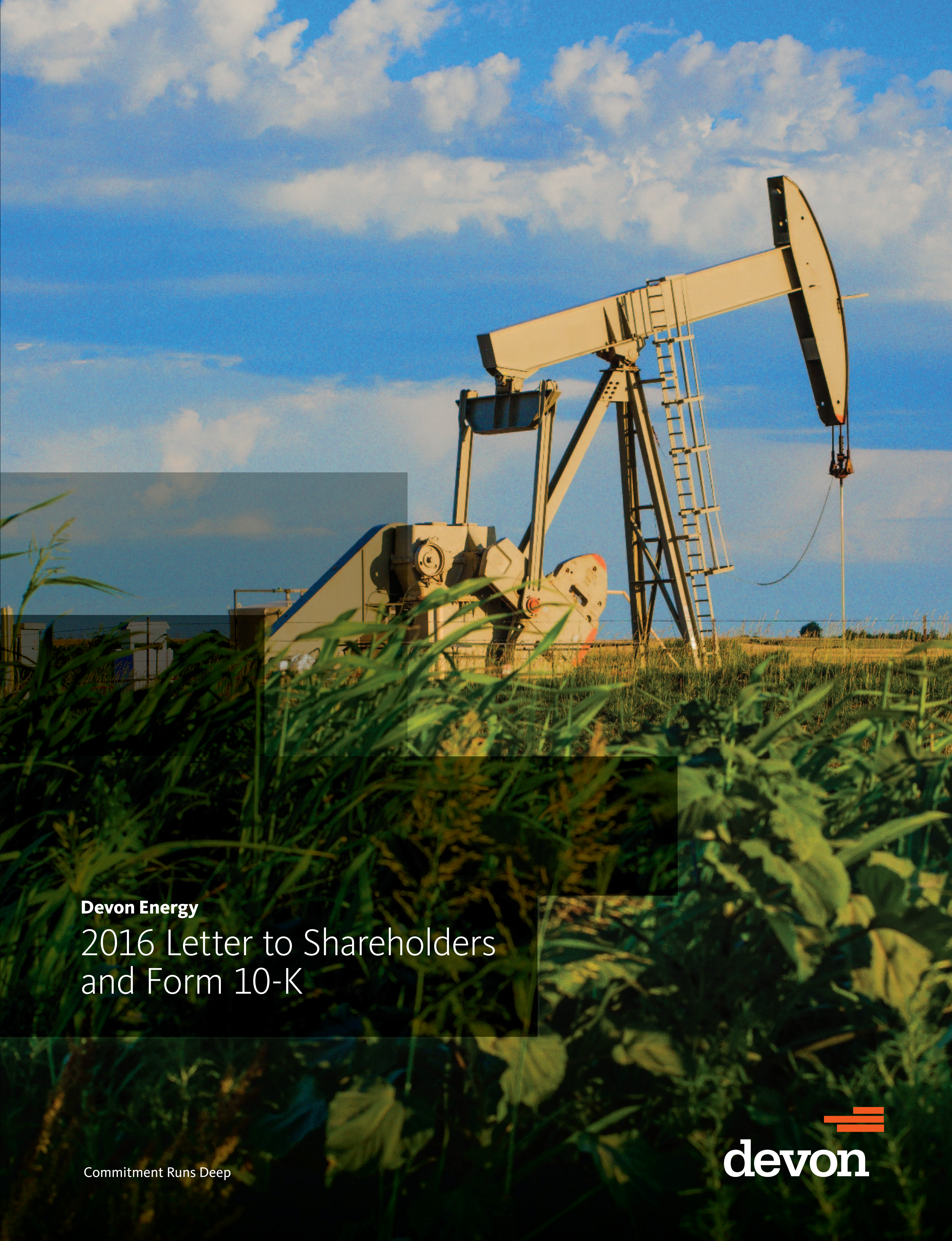


Devon Energy

2016 Letter to Shareholders and Form 10-K

Commitment Runs Deep

devon

Letter to Shareholders

While 2016 will be remembered for volatility in the energy markets, at Devon, we focused on controllable aspects of our business, which produced several noteworthy highlights during the year:

- We reshaped our portfolio by materially expanding upon our leading position in the Oklahoma STACK play and further high-graded our asset base in North America.
- We strengthened our investment-grade financial position, divesting $3.2 billion of noncore assets.
- We executed on drilling programs that generated the best well productivity in Devon's 45-year history.
- Our cost-reduction efforts created $1.3 billion of annual savings, enhancing the value of every barrel produced.
- We grew Devon's reserves in 2016, led by our U.S. assets, which replaced more than 175% of production.

Accelerating Investment

As we look ahead, the next step in our strategic plan is to accelerate investment across our top-tier U.S. resource plays, while staying focused on maintaining our low cost structure to maximize profitability. With an improving cash-flow stream, we plan to ramp up drilling activity in 2017 to as many as 20 operated rigs, doubling our rig count from year-end 2016.

We plan to invest $2 billion to $2.3 billion of upstream capital in 2017, with the majority focused on our highest rate-of-return assets, the STACK and Delaware Basin. This activity is expected to increase Devon's 2017 U.S. light-oil production by 15 percent compared to the fourth quarter of 2016. We also expect to reduce lease operating expenses across our U.S. resource plays by 30 percent from the peak rates of a few years ago, further bolstering profitability.

Looking out further, we're even more encouraged about 2018. With the operational momentum we're seeing across our U.S. portfolio, we're projecting an additional 20 percent gain in U.S. light-oil production next year. This rapid growth in our highest-margin product, combined with our low cost structure, positions Devon to deliver peer-leading cash-flow expansion.

Sustainable Growth Platform

Looking beyond the attractive growth profile we're going to deliver in 2017 and 2018, Devon has the quality and depth of resource to deliver high-return, sustainable growth for many years to come. Between the STACK and Delaware Basin – two of the best-positioned plays on the North American cost curve – we have exposure to more than 1 million net acres of stacked-pay potential.

Across these world-class acreage positions, we have identified more than 30,000 potential drilling locations, about a third of which have already been de-risked through successful appraisal work. To further advance our understanding of the ultimate inventory and resource potential within the STACK and Delaware Basin, we have several important appraisal projects under way in 2017. These projects include evaluating tighter spacing for future developments and drilling emerging landing zones. With success, these initiatives could materially expand our risked inventory in these two tremendous plays.

Superior Execution

While possessing a premier portfolio is essential to success in the E&P space, developing the assets through superior execution is equally important. Accordingly, we've honed our business processes and more aggressively incorporated technologies to establish a competitive edge. We've slashed drilling times, created value with industry-leading completion designs and optimized base production with sharply focused field operations.

Never satisfied, our teams continue their pursuit of new ways to improve efficiency and productivity in all aspects of our business – drilling, supply chain and information technology, where we're at the forefront of emerging trends in predictive analytics and artificial intelligence.

The future looks bright for Devon. Supported by our investment-grade financial strength, we have the right assets, the right technical staff and the right culture to deliver peer-leading performance for all of our stakeholders.

Sincerely,

David A. Hager

Dave Hager
President and CEO

April 3, 2017

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

Form 10-K

(Mark One)

☒ **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**

Commission File Number 001-32318

DEVON ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**73-1567067**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer identification No.)*
333 West Sheridan Avenue, Oklahoma City, Oklahoma	**73102-5015**
(Address of principal executive offices)	*(Zip code)*

Registrant's telephone number, including area code:
(405) 235-3611

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

Title of each class	Name of each exchange on which registered
Common stock, par value $0.10 per share	**The 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. 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 ☐ 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. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of 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 ☒ 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 ☐ No ☒

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2016 was approximately $18.9 billion, based upon the closing price of $36.25 per share as reported by the New York Stock Exchange on such date. On February 8, 2017, 524.6 million shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2017 annual meeting of stockholders – Part III

DEVON ENERGY CORPORATION
FORM 10-K
TABLE OF CONTENTS

DEFINITIONS

Unless the context otherwise indicates, references to "us," "we," "our," "ours," "Devon" and the "Company" refer to Devon Energy Corporation and its consolidated subsidiaries. In addition, the following are other abbreviations and definitions of certain terms used within this Annual Report on Form 10-K:

"2009 Plan" means the Devon Energy Corporation 2009 Long-Term Incentive Plan, as amended and restated.

"2015 Plan" means the Devon Energy Corporation 2015 Long-Term Incentive Plan.

"ASU" means Accounting Standards Update.

"Bbl" or "Bbls" means barrel or barrels.

"Bcf" means billion cubic feet.

"BLM" means the United States Bureau of Land Management.

"Boe" means barrel of oil equivalent. Gas proved reserves and production are converted to Boe, at the pressure and temperature base standard of each respective state in which the gas is produced, at the rate of six Mcf of gas per Bbl of oil, based upon the approximate relative energy content of gas and oil. Bitumen and NGL proved reserves and production are converted to Boe on a one-to-one basis with oil.

"Btu" means British thermal units, a measure of heating value.

"Canada" means the division of Devon encompassing oil and gas properties located in Canada. All dollar amounts associated with Canada are in U.S. dollars, unless stated otherwise.

"Canadian Plan" means Devon Canada Corporation Incentive Savings Plan.

"Coronado" means Coronado Midstream Holdings LLC.

"Crosstex" means Crosstex Energy, Inc. together with Crosstex Energy L.P.

"DD&A" means depreciation, depletion and amortization expenses.

"Devon Financing" means Devon Financing Company, L.L.C.

"Devon Plan" means Devon Energy Corporation Incentive Savings Plan.

"E2" means E2 Energy Services, LLC together with E2 Appalachian Compression, LLC.

"EMH" means EnLink Midstream Holdings, LP.

"EnLink" means EnLink Midstream Partners, L.P., a master limited partnership.

"EPA" means the United States Environmental Protection Agency.

"FASB" means Financial Accounting Standards Board.

"Federal Funds Rate" means the interest rate at which depository institutions lend balances at the Federal Reserve to other depository institutions overnight.

"G&A" means general and administrative expenses.

"GAAP" means U.S. generally accepted accounting principles.

"General Partner" means EnLink Midstream, LLC, the indirect general partner entity of EnLink.

"GeoSouthern" means GeoSouthern Energy Corporation.

"Inside FERC" refers to the publication *Inside F.E.R.C.'s Gas Market Report.*

"LIBOR" means London Interbank Offered Rate.

"LOE" means lease operating expenses.

"LPC" means LPC Crude Oil Marketing LLC.

"Matador" means MRC Energy Company.

"MBbls" means thousand barrels.

"MBoe" means thousand Boe.

"Mcf" means thousand cubic feet.

"MLP" means master limited partnership.

"MMBbls" means million barrels.

"MMBoe" means million Boe.

"MMBtu" means million Btu.

"MMcf" means million cubic feet.

"N/M" means not meaningful.

"NGL" or "NGLs" means natural gas liquids.

"NYMEX" means New York Mercantile Exchange.

"NYSE" means New York Stock Exchange.

"OPEC" means Organization of the Petroleum Exporting Countries.

"OPIS" means Oil Price Information Service.

"PHMSA" means United States Department of Transportation Pipeline and Hazardous Materials Safety Administration.

"SEC" means United States Securities and Exchange Commission.

"Senior Credit Facility" means Devon's syndicated unsecured revolving line of credit.

"Standardized measure" means the present value of after-tax future net revenues discounted at 10% per annum.

"S&P 500 Index" means Standard and Poor's 500 index.

"Tall Oak" means Tall Oak Midstream, LLC.

"TSR" means total shareholder return.

"U.S." means United States of America.

"VEX" means Victoria Express Pipeline and related truck terminal and storage assets.

"WTI" means West Texas Intermediate.

"/d" means per day.

"/gal" means per gallon.

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This report includes "forward-looking statements" as defined by the SEC. Such statements include those concerning strategic plans, our expectations and objectives for future operations, as well as other future events or conditions, and are often identified by use of the words "expects," "believes," "will," "would," "could," "forecasts," "projections," "estimates," "plans," "expectations," "targets," "opportunities," "potential," "anticipates," "outlook" and other similar terminology. Such forward-looking statements are based on our examination of historical operating trends, the information used to prepare our December 31, 2016 reserve reports and other data in our possession or available from third parties. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond our control. Consequently, actual future results could differ materially from our expectations due to a number of factors, including, but not limited to:

- the volatility of oil, gas and NGL prices;
- uncertainties inherent in estimating oil, gas and NGL reserves;
- the extent to which we are successful in acquiring and discovering additional reserves;
- the uncertainties, costs and risks involved in exploration and development activities;
- risks related to our hedging activities;
- counterparty credit risks;
- regulatory restrictions, compliance costs and other risks relating to governmental regulation, including with respect to environmental matters;
- risks relating to our indebtedness;
- our ability to successfully complete mergers, acquisitions and divestitures;
- the extent to which insurance covers any losses we may experience;
- our limited control over third parties who operate some of our oil and gas properties;
- midstream capacity constraints and potential interruptions in production;
- competition for leases, materials, people and capital;
- cyberattacks targeting our systems and infrastructure; and
- any of the other risks and uncertainties discussed in this report.

All subsequent written and oral forward-looking statements attributable to Devon, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements above. We assume no duty to update or revise our forward-looking statements based on new information, future events or otherwise.

PART I

Items 1 and 2. *Business and Properties*

General

A Delaware corporation formed in 1971, Devon is an independent energy company engaged primarily in the exploration, development and production of oil, natural gas and NGLs. Our operations are concentrated in various North American onshore areas in the U.S. and Canada. Additionally, we control EnLink, a publicly–traded MLP with an integrated midstream business with significant size and scale in key operating regions in the U.S. For additional information regarding our control of, and ownership interest in, EnLink and its indirect general partner, the General Partner, see Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Devon has been publicly held since 1988, and our common stock is listed on the NYSE under the ticker symbol DVN. Our principal and administrative offices are located at 333 West Sheridan, Oklahoma City, OK 73102-5015 (telephone 405-235-3611). As of December 31, 2016, Devon and its consolidated subsidiaries had approximately 5,000 employees, of which approximately 1,500 employees are employed by EnLink (through its subsidiaries).

Devon files or furnishes annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K as well as any amendments to these reports with the SEC. Through our website, www.devonenergy.com, we make available electronic copies of the documents we file or furnish to the SEC, the charters of the committees of our Board of Directors and other documents related to our corporate governance. The corporate governance documents available on our website include our Code of Ethics for Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, and any amendments to and waivers from any provision of that Code will also be posted on our website. Access to these electronic filings is available free of charge as soon as reasonably practicable after filing or furnishing them to the SEC. Printed copies of our committee charters or other governance documents and filings can be requested by writing to our corporate secretary at the address on the cover of this report.

In addition, the public may read and copy any materials Devon files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington D.C. 20549. The public may also obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Reports filed with the SEC are also made available on its website at www.sec.gov.

Devon Strategy

Devon is committed to delivering consistent top-quartile shareholder return among its peer group through a highly engaged culture focused on innovation, safety, operational excellence, environmental stewardship and social responsibility. We also maintain a strong commitment to financial strength and flexibility through all commodity price cycles, as reflected in the company's investment grade credit ratings. We focus our business on building value per share by:

- managing a premier asset portfolio;
- delivering top-tier results within the areas that we operate;
- continuing disciplined capital allocation; and
- maintaining significant financial strength.

Our formidable portfolio of exploration and production assets and operations provides stable, environmentally responsible production and a platform for future growth. For Devon, 2016 was a transformational year as we executed our strategy. We successfully reshaped our asset portfolio with non-core divestitures and the continued development of our world-class operations in the STACK and Delaware Basin. These assets provide us with a sustainable, multi-decade growth platform that continues to improve in response to our successful drilling programs. During 2016, we delivered the best well productivity in Devon's 45-year history and continued a four-year streak of increasing Devon's initial 90-day production rates. Devon has more than doubled its onshore North American oil production since 2011 and has a deep inventory of development opportunities to deliver future oil growth. Adding to these operational highlights, we had several key actions in 2016 as discussed below.

- Raised net proceeds of $1.5 billion in an offering of our common stock
- Reduced exploratory and development capital investment by $2.8 billion, or 65%
- Reduced G&A and field operating costs by $845 million, or 25%
- Reduced our dividend $175 million, or 44%
- Successfully divested certain non-core upstream assets in the U.S. and our 50% interest in the Access Pipeline in Canada for approximately $3.1 billion
- Reduced Devon's debt by $3.1 billion, or 31%, and have no significant long term maturities until July 2021
- Completed a strategic bolt-on acquisition in the STACK for $1.5 billion
- Exited 2016 with approximately $5 billion in liquidity

As we enter 2017 and continue to look toward the future, we will approach the current environment in a manner that drives efficiencies across our portfolio. We will manage activity levels within our cash flow by achieving additional operating cost savings and increasing capital productivity, while remaining committed to allocating capital in a disciplined manner that is driven by both value and return. We believe we capture the full value of our assets and improve returns through maximizing our base production and optimizing our capital program. The activities that support this strategy include minimizing controllable downtime, enhancing well productivity, ensuring disciplined project execution, performing premier technical work, focusing on developmental drilling and reducing our operating and capital costs.

EnLink Strategy

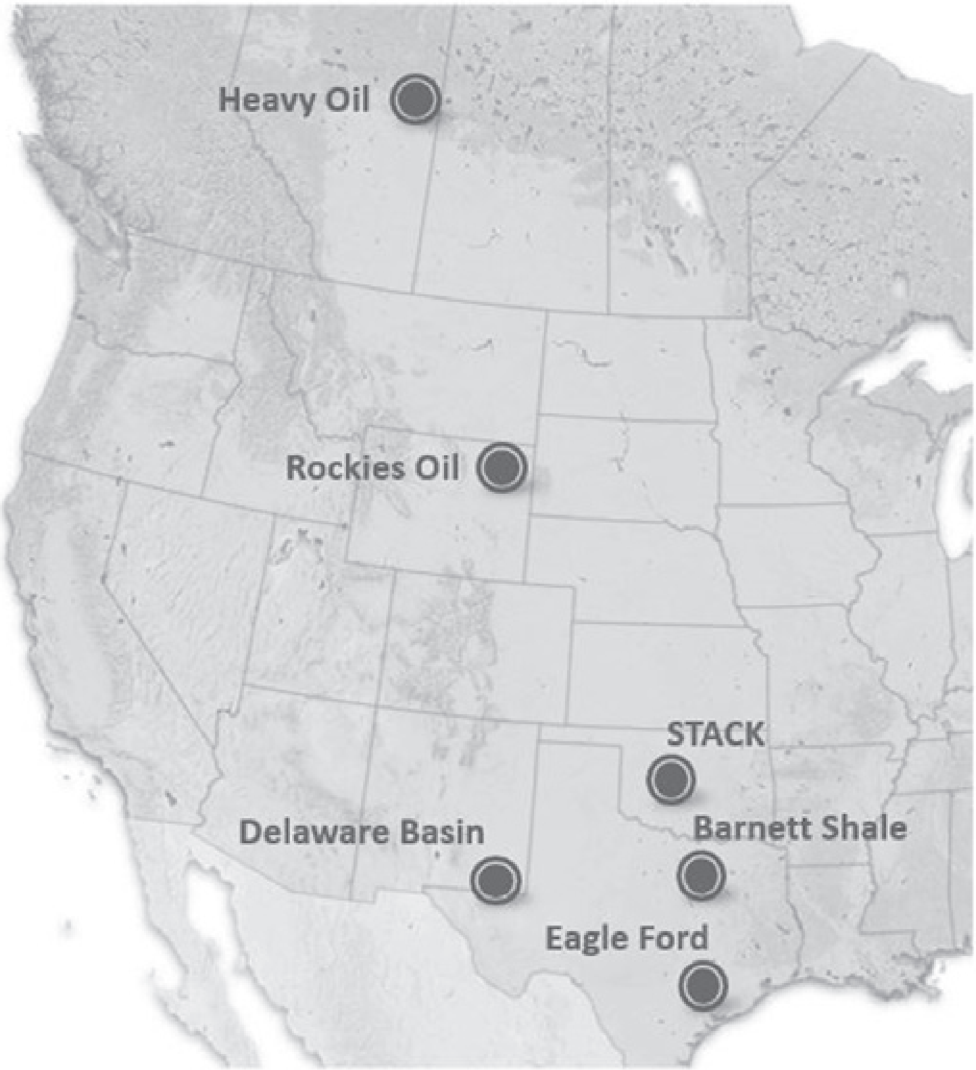
EnLink focuses on providing gathering, transmission, processing, storage, fractionation and marketing to upstream oil and natural gas producers, including Devon.

EnLink connects the wells of natural gas producers in its market areas to its gathering systems, processes natural gas for the removal of NGLs, fractionates NGLs into purity products and markets those products for a fee, transports natural gas and ultimately provides natural gas to a variety of markets. Furthermore, EnLink purchases natural gas from natural gas producers and other supply sources and sells that natural gas to utilities, industrial consumers, other marketers and pipelines.

EnLink's primary business objective is to provide cash flow stability, while growing through prudent and profitable investments. EnLink accomplishes its objectives through long-term, fee-based contracts and maintaining a strong financial position through a conservative and balanced capital structure highlighted by its investment grade status. EnLink has consistently demonstrated expertise within the MLP space and continues to employ a proven business model that includes growing, expanding and executing on its strategy within top basins where Devon and other successful upstream producers operate.

Oil and Gas Properties

Property Profiles



The following table outlines a summary of key data in each of our operating areas as of and for the year ended December 31, 2016. Notes 21 and 22 to the financial statements included in “Item 8. Financial Statements and Supplementary Data” of this report contain additional information on our segments and geographical areas.

	Proved Reserves			Production			
	MMBoe	% of Total	% Liquids	MBoe/d	% of Total	% Liquids	Gross Wells Drilled
Barnett Shale	895	44%	25%	169	28%	27%	—
Delaware Basin	108	5%	75%	60	10%	74%	58
Eagle Ford	75	4%	76%	76	12%	76%	63
Heavy Oil	504	24%	99%	134	22%	98%	25
Rockies Oil	24	1%	64%	19	3%	79%	19
STACK	393	19%	47%	93	15%	48%	133
Other	59	3%	90%	17	3%	81%	28
Retained assets	2,058	100%	54%	568	93%	62%	326
Divested assets (1)	—	—	—	43	7%	51%	14
Total	2,058	100%	54%	611	100%	61%	340

(1) As of December 31, 2016, these assets had been divested and therefore had no associated reserves.

Led by results from the STACK, Delaware Basin and Eagle Ford, Devon achieved the best drilling results in our 45-year history. Our initial 90-day production rates in 2016 increased for the fourth consecutive year, advancing more than 300% from 2012 levels. These productivity improvements were driven by activity focused in top resource plays, improved subsurface reservoir characterization, leading-edge completion designs and improvements in lateral placement. Excluding the effects of divestitures, our drilling results increased our proved reserves in 2016 on a retained asset basis by 3%. The most significant reserves growth came from our U.S. operations, where we replaced approximately 175% of our 2016 production.

Barnett Shale – This is our largest property in terms of production and proved reserves. Our leases are located primarily in Denton, Johnson, Parker, Tarrant and Wise counties in north Texas. Since acquiring a substantial position in this field in 2002, we continue to introduce technology and new innovations to optimize production operations and have transformed this asset into one of the top producing gas fields in North America. Given the sustained low gas price environment, we continue to focus on enhancing existing well performance through re-fracturing, artificial lift and line pressure reduction projects. In 2017, we plan on minimal development activity, with planned capital investment of up to $50 million to optimize base production and further de-risk future development activity.

Delaware Basin – The Delaware Basin is one of Devon’s top-two franchise assets and continues to offer exploration and low-risk development opportunities from many geologic reservoirs and play types, including the oil-rich Bone Spring, Delaware, Wolfcamp and Leonard formations. These oil and liquids-rich opportunities across our acreage in the Delaware Basin will offer high-margin growth for many years to come. At December 31, 2016, we had three operated rigs. In 2017, we plan to invest approximately $700 million of capital in the Delaware Basin and steadily ramp up activity with as many as 10 operated rigs running by the end of the year, primarily focused on the Bone Spring, Leonard and Wolfcamp formations.

Eagle Ford – We acquired our position in the Eagle Ford in 2014 from GeoSouthern and have approximately 66,000 net acres located in DeWitt and Lavaca counties in south Texas. Since acquiring these assets, we have delivered tremendous results by producing 94 million oil-equivalent barrels. Our excellent results are driven by our development in DeWitt County, located in the economic core of the play. With the highest margins in our portfolio, our Eagle Ford assets generated approximately $550 million of direct cash margin in 2016. In 2017, we plan approximately $175 million of capital investment.

Heavy Oil – Our operations in Canada are focused on our heavy oil assets in Alberta, Canada. Our most significant Canadian operation is our Jackfish complex, an industry-leading thermal heavy oil operation in the non-conventional oil sands of east central Alberta. We employ a recovery method known as steam-assisted gravity drainage at Jackfish. The Jackfish operation consists of three facilities. In 2014, we brought the third phase of Jackfish into operation, which ramped up to facility capacity by the third quarter of 2015. At $55/Bbl WTI, direct cash margin from our Heavy Oil assets has the potential to approach $800 million in 2017. We expect Jackfish to maintain a reasonably flat production profile for greater than 20 years requiring only approximately $200 million of annual maintenance capital based on current economic conditions.

Our Pike oil sands acreage is situated directly to the southeast of our Jackfish acreage in east central Alberta and has similar reservoir characteristics to Jackfish. The Pike leasehold is currently undeveloped and has no proved reserves or production as of December 31, 2016. With our 50% partner, we continue to evaluate our development timeline for Pike.

In addition to Jackfish and Pike, we hold acreage and own producing assets in the Bonnyville region, located to the south and east of Jackfish in eastern Alberta. Bonnyville is a low-risk, high margin oil development play that produces heavy oil by conventional means, without the need for steam injection.

In 2017, we plan approximately $300 million of capital investment in our Canadian Heavy Oil business.

Rockies Oil – Our acreage in the Rockies includes approximately 470,000 net surface acres, focused on emerging oil opportunities in the Powder River Basin and the Wind River Basin. Recent drilling success in these formations has expanded our drilling inventory, and we expect further growth as we continue to de-risk this emerging light-oil opportunity. As of December 31, 2016, we had one operated rig targeting the Parkman, Teapot and Turner formations within the Cretaceous oil objectives of the Powder River Basin. In 2017, we plan approximately $175 million of capital investment.

STACK – The STACK development, located primarily in Oklahoma's Canadian, Kingfisher and Blaine counties, is one of Devon's top-two franchise assets. Devon has two primary fields in the area: the Woodford Shale and the Meramec. In 2016, we increased our acreage in these positions by acquiring 80,000 net acres in the STACK. Our acreage in the play now includes approximately 430,000 net acres. Our STACK position is the largest and one of the best in the industry, providing visible long-term growth. Recent well-completion design enhancements have resulted in greater productivity and improved economics. Early drilling activity in the Meramec play has produced record setting results across our core position in the oil and liquids window. At December 31, 2016, we had six operated rigs with drilling focused in the Meramec formation. In 2017, we plan approximately $750 million of capital investment and expect to continue to increase drilling activity throughout 2017 and run up to 10 operated rigs by the end of the year.

Proved Reserves

For estimates of our proved developed and proved undeveloped reserves and the discussion of the contribution by each property, see Note 22 in "Item 8. Financial Statements and Supplementary Data" of this report.

Proved oil and gas reserves are those quantities of oil, gas and NGLs which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. To be considered proved, oil and gas reserves must be economically producible before contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Also, the project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The process of estimating oil, gas and NGL reserves is complex and requires significant judgment as discussed in "Item 1A. Risk Factors" of this report. As a result, we have developed internal policies for estimating and recording reserves. Such policies require proved reserves to be in compliance with the SEC definitions and guidance. Our policies assign responsibilities for compliance in reserves bookings to our Reserve Evaluation Group, (the “Group”). These same policies also require that reserve estimates be made by professionally qualified reserves estimators, as defined by the Society of Petroleum Engineers’ standards.

The Group, which is led by Devon’s Director of Reserves and Economics, is responsible for the internal review and certification of reserves estimates. We ensure the Director and key members of the Group have appropriate technical qualifications to oversee the preparation of reserves estimates. The Group reports to and is managed through our finance department. No portion of the Group’s compensation is directly dependent on the quantity of reserves booked.

The Director of the Group has approximately 30 years of industry experience with positions of increasing responsibility for the estimation and evaluation of reserves. He has been employed by Devon for the past 16 years, including the past nine in his current position. His further professional qualifications include a degree in petroleum engineering, registered professional engineer, member of the Society of Petroleum Engineers and experience in reserves estimation for projects in the U.S. (both onshore and offshore), as well as in Canada, Asia, the Middle East and South America.

Throughout the year, the Group performs internal reserves audits of each operating division’s reserves. The Group also oversees audits and reserves estimates performed by qualified third-party petroleum consulting firms. During 2016, we engaged two such firms to audit 89% of our proved reserves in accordance with generally accepted petroleum engineering and evaluation methods and procedures. LaRoche Petroleum Consultants, Ltd. audited 86% of our 2016 U.S. reserves, and Deloitte LLP audited 96% of our Canadian reserves.

In addition to conducting these internal and external reserves audits, we also have a Reserves Committee that consists of three independent members of our Board of Directors. This committee provides additional oversight of our reserves estimation and certification process. The members of our Reserves Committee also have educational backgrounds in geology or petroleum engineering, as well as experience relevant to the reserves estimation process. The Reserves Committee meets a minimum of twice a year to discuss reserves issues and policies and meets at least once a year separately with our senior reserves engineering personnel and separately with our third-party petroleum consultants.

The following tables present production, price and cost information for each significant field, country and continent.

	Production				
Year Ended December 31,	**Oil (MMBbls)**	**Bitumen (MMBbls)**	**Gas (Bcf)**	**NGLs (MMBbls)**	**Total (MMBoe)**
2016					
Barnett Shale	—	—	265	15	60
Jackfish	—	40	—	—	40
U.S.	47	—	510	42	174
Canada	8	40	7	—	49
Total North America	55	40	517	42	223
2015					
Barnett Shale	—	—	291	17	66
Jackfish	—	31	—	—	31
U.S.	60	—	579	50	206
Canada	10	31	8	—	42
Total North America	70	31	587	50	248
2014					
Barnett Shale	1	—	332	20	76
Jackfish	—	20	—	—	20
U.S.	48	—	660	50	207
Canada	10	20	41	1	39
Total North America	58	20	701	51	246

Year Ended December 31,	Average Sales Price Oil (Per Bbl)		Bitumen (Per Bbl)		Gas (Per Mcf)		NGLs (Per Bbl)		Production Cost (Per Boe) [(1)]	
2016										
Barnett Shale	$	41.03	$	—	$	1.76	$	10.31	$	6.16
Jackfish	$	—	$	19.82	$	—	$	—	$	8.70
U.S.	$	38.92	$	—	$	1.84	$	9.81	$	6.44
Canada	$	23.96	$	19.82		N/M	$	—	$	9.36
Total North America	$	36.72	$	19.82	$	1.84	$	9.81	$	7.08
2015										
Barnett Shale	$	46.47	$	—	$	2.00	$	9.62	$	6.02
Jackfish	$	—	$	23.41	$	—	$	—	$	12.43
U.S.	$	44.01	$	—	$	2.17	$	9.32	$	7.52
Canada	$	30.58	$	23.41		N/M	$	—	$	13.18
Total North America	$	42.12	$	23.41	$	2.14	$	9.32	$	8.48
2014										
Barnett Shale	$	95.51	$	—	$	3.78	$	21.98	$	5.25
Jackfish	$	—	$	55.88	$	—	$	—	$	20.59
U.S.	$	85.64	$	—	$	3.92	$	24.46	$	7.52
Canada	$	68.14	$	55.88	$	3.64	$	50.52	$	20.10
Total North America	$	82.47	$	55.88	$	3.90	$	24.89	$	9.49

(1) Represents LOE per Boe and excludes severance and property taxes. Jackfish and Canada costs include purchases of natural gas used to heat the heavy oil reservoirs. The natural gas is generally purchased at prevailing market prices, which vary from year to year.

Drilling Statistics

The following table summarizes our development and exploratory drilling results.

Year Ended December 31,	Development Wells [(1)] Productive	Development Wells [(1)] Dry	Exploratory Wells [(1)] Productive	Exploratory Wells [(1)] Dry	Total Wells [(1)] Productive	Total Wells [(1)] Dry	Total Wells [(1)] Total
2016							
U.S.	88.5	—	36.4	2.0	124.9	2.0	126.9
Canada	21.5	—	—	—	21.5	—	21.5
Total North America	110.0	—	36.4	2.0	146.4	2.0	148.4
2015							
U.S.	298.6	1.8	40.7	—	339.3	1.8	341.1
Canada	79.0	—	—	—	79.0	—	79.0
Total North America	377.6	1.8	40.7	—	418.3	1.8	420.1
2014							
U.S.	474.4	0.4	5.0	1.2	479.4	1.6	481.0
Canada	190.8	1.0	—	0.5	190.8	1.5	192.3
Total North America	665.2	1.4	5.0	1.7	670.2	3.1	673.3

(1) These well counts represent net wells completed during each year. Net wells are gross wells multiplied by our fractional working interests in each well.

The following table presents the wells that were in progress on December 31, 2016. As of February 1, 2017, these wells were still in progress.

	Gross (1)	Net (2)
U.S.	42.0	14.5
Canada	10.0	10.0
Total North America	52.0	24.5

(1) Gross wells are the sum of all wells in which we own a working interest.
(2) Net wells are gross wells multiplied by our fractional working interests in each well.

Productive Wells

The following table sets forth our producing wells as of December 31, 2016.

	Oil Wells (1)		Natural Gas Wells		Total Wells (1)	
	Gross (2)(4)	Net (3)	Gross (2)(4)	Net (3)	Gross (2)(4)	Net (3)
U.S.	9,710	3,499	10,061	7,577	19,771	11,076
Canada	3,239	3,138	644	456	3,883	3,594
Total North America	12,949	6,637	10,705	8,033	23,654	14,670

(1) Includes bitumen wells.
(2) Gross wells are the sum of all wells in which we own a working interest.
(3) Net wells are gross wells multiplied by our fractional working interests in each well.
(4) Includes 822 and 404 gross oil and gas wells, respectively, which had multiple completions.

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs field personnel and performs other functions. We are the operator of approximately 15,200 gross wells. As operator, we receive reimbursement for direct expenses incurred to perform our duties, as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged in the respective areas. In presenting our financial data, we record the monthly overhead reimbursements as a reduction of G&A, which is a common industry practice.

Acreage Statistics

The following table sets forth our developed and undeveloped lease and mineral acreage as of December 31, 2016. Of our 4.6 million net acres, approximately 2.4 million acres are held by production. The acreage in the table includes 0.3 million, 0.2 million and 0.1 million net acres subject to leases that are scheduled to expire during 2017, 2018 and 2019, respectively. As of December 31, 2016, there were no proved undeveloped reserves associated with our expiring acreage. Of the 0.6 million net acres set to expire by December 31, 2019, we will perform operational and administrative actions to continue the lease terms for portions of the acreage that we intend to further assess. However, we do expect to allow a portion of the acreage to expire in the normal course of business. In 2016, we allowed approximately 0.3 million acres to expire, which is consistent with expirations in prior years.

	Developed		Undeveloped		Total	
	Gross [(1)]	Net [(2)]	Gross [(1)]	Net [(2)]	Gross [(1)]	Net [(2)]
	(Thousands)					
U.S.	1,800	1,218	4,138	1,917	5,938	3,135
Canada	695	512	2,075	953	2,770	1,465
Total North America	2,495	1,730	6,213	2,870	8,708	4,600

(1) Gross acres are the sum of all acres in which we own a working interest.
(2) Net acres are gross acres multiplied by our fractional working interests in the acreage.

Title to Properties

Title to properties is subject to contractual arrangements customary in the oil and gas industry, liens for taxes not yet due and, in some instances, other encumbrances. We believe that such burdens do not materially detract from the value of properties or from the respective interests therein or materially interfere with their use in the operation of the business.

As is customary in the industry, other than a preliminary review of local records, little investigation of record title is made at the time of acquisitions of undeveloped properties. Title investigations, which generally include a review of title opinions of outside counsel, are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

EnLink Midstream Properties

EnLink represents the primary component of our midstream operations. EnLink's assets are comprised of systems and other assets located in four primary regions:

- *Texas* – The Texas assets consist of transmission pipelines with a capacity of approximately 920 MMcf/d, processing facilities with a total processing capacity of approximately 1.6 Bcf/d and gathering systems with total capacity of approximately 2.3 Bcf/d.
- *Oklahoma* – The Oklahoma assets consist of processing facilities with a total processing capacity of approximately 795 MMcf/d and gathering systems with total capacity of approximately 810 MMcf/d.
- *Louisiana* – The Louisiana assets consist of transmission pipelines with a capacity of approximately 3.5 Bcf/d, processing facilities with a total processing capacity of approximately 1.9 Bcf/d, gathering systems with total capacity of approximately 510 MMcf/d, 720 miles of liquids transport lines and four fractionation assets with total fractionation capacity of 175 MBbls/d.
- *Crude and Condensate* – The Crude and Condensate assets consist of approximately 540 miles of crude oil and condensate pipelines with total capacity of approximately 116 MBbls/d, 900 MBbls of above ground storage and eight condensate stabilization and natural gas compression stations with combined capacities of approximately 36 MBbls/d of condensate stabilization and 780 MMcf/d of natural gas compression.

Marketing Activities

Oil, Gas and NGL Marketing

The spot markets for oil, gas and NGLs are subject to volatility as supply and demand factors fluctuate. As detailed below, we sell our production under both long-term (one year or more) and short-term (less than one year) agreements at prices negotiated with third parties. Regardless of the term of the contract, the vast majority of our production is sold at variable, or market-sensitive, prices.

Additionally, we may enter into financial hedging arrangements or fixed-price contracts associated with a portion of our oil, gas and NGL production. These activities are intended to support targeted price levels and to manage our exposure to price fluctuations. See Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report for further information.

As of January 2017, our production was sold under the following contract terms.

	Short-Term		Long-Term	
	Variable	Fixed	Variable	Fixed
Oil and bitumen	65%	—	35%	—
Natural gas	54%	4%	42%	—
NGLs	53%	17%	30%	—

Delivery Commitments

A portion of our production is sold under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. As of December 31, 2016, we were committed to deliver the following fixed quantities of production.

	Total	Less Than 1 Year	1-3 Years	3-5 Years
Oil and bitumen (MMBbls)	112	36	48	28
Natural gas (Bcf)	487	338	149	—
NGLs (MMBbls)	9	9	—	—
Total (MMBoe)	202	101	73	28

We expect to fulfill our delivery commitments primarily with production from our proved developed reserves. Moreover, our proved reserves have generally been sufficient to satisfy our delivery commitments during the three most recent years, and we expect such reserves will continue to be the primary means of fulfilling our future commitments. However, where our proved reserves are not sufficient to satisfy our delivery commitments, we can and may use spot market purchases to satisfy the commitments.

Customers

During 2016, 2015 and 2014, no purchaser accounted for over 10% of our consolidated sales revenue.

Competition

See "Item 1A. Risk Factors."

Public Policy and Government Regulation

Our industry is subject to a wide range of regulations. Laws, rules, regulations, taxes, fees and other policy implementation actions affecting our industry have been pervasive and are under constant review for amendment or expansion. Numerous government agencies have issued extensive regulations which are binding on our industry and its individual members, some of which carry substantial penalties for failure to comply. These laws and regulations increase the cost of doing business and consequently affect profitability. Because public policy changes are commonplace, and existing laws and regulations are frequently amended, we are unable to predict the future cost or impact of compliance. However, we do not expect that any of these laws and regulations will affect our operations materially differently than they would affect other companies with similar operations, size and financial strength. The following are significant areas of government control and regulation affecting our operations.

Exploration and Production Regulation

Our operations are subject to federal, tribal, state, provincial and local laws and regulations. These laws and regulations relate to matters that include:

- acquisition of seismic data;
- location, drilling and casing of wells;
- well design;
- hydraulic fracturing;
- well production;
- spill prevention plans;
- emissions and discharge permitting;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- plugging and abandoning of wells;
- transportation of production; and
- endangered species and habitat.

Our operations also are subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units; the number of wells that may be drilled in a unit; the rate of production allowable from oil and gas wells; and the unitization or pooling of oil and gas properties. In the U.S., some states allow the forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases, which may make it more difficult to develop oil and gas properties. In addition, federal and state conservation laws generally limit the venting or flaring of natural gas, and state conservation laws impose certain requirements regarding the ratable purchase of production. These regulations limit the amounts of oil and gas we can produce from our wells and the number of wells or the locations at which we can drill.

Certain of our U.S. natural gas and oil leases are granted or approved by the federal government and administered by the BLM or Bureau of Indian Affairs of the Department of the Interior. Such leases require compliance with detailed federal regulations and orders that regulate, among other matters, drilling and operations on lands covered by these leases and calculation and disbursement of royalty payments to the federal government, tribes or tribal members. The federal government has been particularly active in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding, venting and flaring, oil and gas measurement and royalty payment obligations for production from federal lands. In addition, permitting activities on federal lands are subject to frequent delays.

Royalties and Incentives in Canada

The royalty calculation in Canada is a significant factor in the profitability of Canadian oil and gas production. Oil sands crown royalties are determined by government regulations and are generally calculated as a percentage of the value of the gross production, net of allowed deductions. The royalty percentage is determined on a sliding-scale based on crown posted prices. For pre-payout oil sands projects, the regulations prescribe lower royalty rates for oil sands projects until allowable capital costs have been recovered. In early 2016, the Alberta government adopted the recommendation of its Royalty Review Panel. The new royalty framework preserves the existing royalty structure and rates for oil sands. For conventional oil and gas royalty calculations for wells drilled after January 1, 2017 in the Modernized Royalty Framework, the calculation is based on a percentage of production net of allowed deductions.

Marketing in Canada

Any oil or gas export requires an exporter to obtain export authorizations from Canada's National Energy Board.

Environmental, Pipeline Safety and Occupational Regulations

We are subject to many federal, state, provincial, tribal and local laws and regulations concerning occupational safety and health as well as the discharge of materials into, and the protection of, the environment. Environmental laws and regulations relate to:

- the discharge of pollutants into federal, provincial and state waters;
- assessing the environmental impact of seismic acquisition, drilling or construction activities;
- the generation, storage, transportation and disposal of waste materials, including hazardous substances;
- the emission of certain gases into the atmosphere;
- the monitoring, abandonment, reclamation and remediation of well and other sites, including sites of former operations;
- the development of emergency response and spill contingency plans;
- the monitoring, repair and design of pipelines used for the transportation of oil and natural gas; and
- worker protection.

Failure to comply with these laws and regulations can lead to the imposition of remedial liabilities, administrative, civil or criminal fines or penalties or injunctions limiting our operations in affected areas. Moreover, multiple environmental laws provide for citizen suits, which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law. We consider the costs of environmental protection and safety and health compliance necessary, manageable parts of our business. We have been able to plan for and comply with environmental, safety and health initiatives without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to the protection of the environment and safety and health compliance have increased over the years and may continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters.

Item 1A. *Risk Factors*

Our business and operations, and our industry in general, are subject to a variety of risks. The risks described below may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. If any of the following risks should occur, our business, financial condition, results of operations and liquidity could be materially and adversely impacted. As a result, holders of our securities could lose part or all of their investment in Devon.

Volatile Oil, Gas and NGL Prices Significantly Impact our Business

Our financial condition, results of operations and the value of our properties are highly dependent on the general supply and demand for oil, gas and NGLs, which impact the prices we ultimately realize on our sales of these commodities. Historically, market prices and our realized prices have been volatile. For example, during the period from January 1, 2014 to December 31, 2016, NYMEX WTI oil prices ranged from a high of $107.26 per Bbl to a low of $26.21 per Bbl. Average daily prices for NYMEX Henry Hub gas ranged from a high of $6.15 per MMBtu to a low of $1.64 per MMBtu during the same period. Such volatility is likely to continue in the future due to numerous factors beyond our control, including, but not limited to:

- supply of and demand for oil, gas and NGLs, including consumer demand in emerging markets, such as China;
- volatility and trading patterns in the commodity-futures markets;
- conservation and environmental protection efforts;
- production levels of members of OPEC, Russia or other producing countries;
- geopolitical risks, including political and civil unrest in the Middle East and Africa;
- adverse weather conditions and natural disasters, such as tornadoes, earthquakes and hurricanes;
- regional pricing differentials;
- differing quality of oil produced (i.e., sweet crude versus heavy or sour crude);
- differing quality and NGL content of gas produced;
- the level of imports and exports of oil, gas and NGLs and the level of global oil, gas and NGL inventories;
- the price and availability of alternative fuels;
- technological advances affecting energy consumption;
- the overall economic environment; and
- governmental regulations and taxes.

In the second half of 2014, global energy commodity prices began a rapid and significant decline, which continued through 2015 and into 2016. This commodity price decline adversely affected our business and results of operations and led to substantial impairments to our oil and gas properties during 2015 and 2016. A sustained weakness or further deterioration in commodity prices could materially and adversely impact our business by resulting in, or exacerbating, the following effects:

- reducing the amount of oil, gas and NGLs that we can produce economically;
- limiting our financial flexibility, liquidity and access to sources of capital, such as equity and debt;
- reducing our revenues, operating cash flows and profitability;
- causing us to decrease our capital expenditures or maintain reduced capital spending for an extended period, resulting in lower future production of oil, gas and NGLs; and
- reducing the carrying value of our properties, resulting in additional noncash write-downs.

Estimates of Oil, Gas and NGL Reserves Are Uncertain and May Be Subject to Revision

The process of estimating oil, gas and NGL reserves is complex and requires significant judgment in the evaluation of available geological, engineering and economic data for each reservoir, particularly for new discoveries. Because of the high degree of judgment involved, different reserve engineers may develop different estimates of reserve quantities and related revenue based on the same data. In addition, the reserve estimates for a given reservoir may change substantially over time as a result of several factors, including additional development activity, the viability of production under varying economic conditions, including commodity price declines, and variations in production levels and associated costs. Consequently, material revisions to existing reserve estimates may occur as a result of changes in any of these factors. Such revisions to proved reserves could have a material adverse effect on our financial condition and the value of our properties, as well as the estimates of our future net revenue and profitability. Our policies and internal controls related to estimating and recording reserves are included in “Items 1 and 2. Business and Properties” of this report.

Discoveries or Acquisitions of Reserves Are Needed to Avoid a Material Decline in Reserves and Production

The production rates from oil and gas properties generally decline as reserves are depleted, while related per unit production costs generally increase, due to decreasing reservoir pressures and other factors. Therefore, our estimated proved reserves and future oil, gas and NGL production will decline materially as reserves are produced unless we conduct successful exploration and development activities, such as identifying additional producing zones in existing wells, utilizing secondary or tertiary recovery techniques or acquiring additional properties containing proved reserves. Consequently, our future oil, gas and NGL production and related per unit production costs are highly dependent upon our level of success in finding or acquiring additional reserves.

Future Exploration and Drilling Results Are Uncertain and Involve Substantial Costs

Our exploration and development activities are subject to numerous costs and risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. Drilling for oil, gas and NGLs can be unprofitable, not only from dry holes, but from productive wells that do not return a profit because of insufficient revenue from production or high costs. Substantial costs are required to locate, acquire and develop oil and gas properties, and we are often uncertain as to the amount and timing of those costs. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Declines in commodity prices and overruns in budgeted expenditures are common risks that can make a particular project uneconomic or less economic than forecasted. While both exploratory and developmental drilling activities involve these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. In addition, our oil and gas properties can become damaged, our drilling operations may be curtailed, delayed or canceled and the costs of such operations may increase as a result of a variety of factors, including, but not limited to:

- unexpected drilling conditions, pressure conditions or irregularities in reservoir formations;
- equipment failures or accidents;
- fires, explosions, blowouts and surface cratering;
- adverse weather conditions and natural disasters, such as tornadoes, earthquakes and hurricanes;
- issues with title or in receiving governmental permits or approvals;
- lack of access to pipelines or other transportation methods;
- environmental hazards or liabilities;
- restrictions in access to, or disposal of, water used or produced in drilling and completion operations; and
- shortages or delays in the availability of services or delivery of equipment.

The occurrence of one or more of these factors could result in a partial or total loss of our investment in a particular property, and certain of these events, particularly equipment failures or accidents, could impact third parties, including persons living in proximity to our operations, our employees and employees of our contractors, leading to possible injuries, death or significant property damage.

We Are Subject to Extensive Governmental Regulation, Which Can Change and Could Adversely Impact Our Business

Our operations are subject to extensive federal, state, provincial, tribal, local and other laws, rules and regulations, including with respect to environmental matters, worker health and safety, wildlife conservation, the gathering and transportation of oil, gas and NGLs, conservation policies, reporting obligations, royalty payments, unclaimed property and the imposition of taxes. Such regulations include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling, completion and well operations. If permits are not issued, or if unfavorable restrictions or conditions are imposed on our drilling or completion activities, we may not be able to conduct our operations as planned. In addition, we may be required to make large expenditures to comply with applicable governmental laws, rules, regulations, permits or orders. For example, certain regulations require the plugging and abandonment of wells and removal of production facilities by current and former operators, which may result in significant costs associated with the removal of tangible equipment and other restorative actions at the end of operations.

In addition, changes in public policy have affected, and at times in the future could affect, our operations. Regulatory developments could, among other things, restrict production levels, impose price controls, change environmental protection requirements and increase taxes, royalties and other amounts payable to governments or governmental agencies. Our operating and other compliance costs could increase further if existing laws and regulations are revised or reinterpreted or if new laws and regulations become applicable to our operations. Although we are unable to predict changes to existing laws and regulations, such changes could significantly impact our profitability, financial condition and liquidity, particularly changes related to hydraulic fracturing, pipeline safety, seismic activity, income taxes and climate change, as discussed below.

Hydraulic Fracturing – The EPA and other federal agencies, including the BLM, have made proposals that would subject hydraulic fracturing to further regulation and could restrict the practice of hydraulic fracturing. For example, the EPA has issued final regulations under the federal Clean Air Act establishing performance standards for oil and gas activities, including standards for the capture of air emissions released during hydraulic fracturing and finalized in June 2016 regulations that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. The EPA also released a study in December 2016 finding that certain aspects of hydraulic fracturing, such as water withdrawals and wastewater management practices, could result in impacts to water resources, although the report did not identify a direct link between hydraulic fracturing and impacts to groundwater resources. The BLM and several states have already adopted and more states are considering adopting laws and/or regulations that require disclosure of chemicals used in hydraulic fracturing and impose more stringent permitting, disclosure and well-construction requirements on hydraulic fracturing operations. In addition, some states and municipalities have significantly limited drilling activities and/or hydraulic fracturing or are considering doing so. Although it is not possible at this time to predict the final outcome of these proposals, any new federal, state or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could potentially result in increased compliance costs, delays in development or restrictions on our operations.

Pipeline Safety – The pipeline assets in which we own interests, through EnLink or otherwise, are subject to stringent and complex regulations related to pipeline safety and integrity management. The PHMSA has established a series of rules that require pipeline operators to develop and implement integrity management programs for gas, NGL and condensate transmission pipelines as well as certain low stress pipelines and gathering lines transporting hazardous liquids, such as oil, that, in the event of a failure, could affect “high consequence areas.” Additional action by PHMSA with respect to pipeline integrity management requirements may occur in the future. For example, in March 2016 PHMSA proposed new rules for gas pipelines that extend pipeline safety programs beyond high consequence areas to newly proposed “moderate consequence areas” and would also impose more rigorous testing and reporting requirements on such pipelines. More recently, in January 2017, PHMSA finalized regulations for hazardous liquid pipelines that significantly extend and expand the reach of certain PHMSA integrity management requirements (i.e., periodic assessments, leak detection and repairs), regardless of the pipeline’s proximity to a high consequence area. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. At this time, we cannot predict the cost of such requirements, but they could be significant. Moreover, violations of pipeline safety regulations can result in the imposition of significant penalties.

Seismic Activity – Recent earthquakes in northern and central Oklahoma and elsewhere have prompted concerns about seismic activity and possible relationships with the energy industry. Legislative and regulatory initiatives intended to address these concerns may result in additional levels of regulation that could lead to operational delays, increase our operating and compliance costs or otherwise adversely affect our operations. In addition, we are currently defending against certain third-party lawsuits and could be subject to additional claims, seeking alleged property damages or other remedies as a result of alleged induced seismic activity in our areas of operation.

Potential Changes to Tax Laws – We are subject to U.S. federal income tax as well as income or capital taxes in various state and foreign jurisdictions, and our operating cash flow is sensitive to the amount of income taxes we must pay. In the jurisdictions in which we operate, income taxes are assessed on our earnings after consideration of all allowable deductions and credits. Changes in the types of earnings that are subject to income tax, the types of costs that are considered allowable deductions or the rates assessed on our taxable earnings would all impact our income taxes and resulting operating cash flow. In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but not been limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Congress could consider, and could include, some or all of these proposals as part of tax reform legislation, to accompany lower federal income tax rates. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expense, may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs, and any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Climate Change – Policy makers in the U.S. and Canada are increasingly focusing on whether the emissions of greenhouse gases, such as carbon dioxide and methane, are contributing to harmful climatic changes. Policy makers at both the U.S. federal and state levels have introduced legislation and proposed new regulations designed to quantify and limit the emission of greenhouse gases through inventories, limitations and/or taxes on greenhouse gas emissions. For example, both the EPA and the BLM have issued regulations for the control of methane emissions, which also include leak detection and repair requirements, for the oil and gas industry. Legislative and state initiatives to date have generally focused on the development of cap-and-trade and/or carbon tax programs. A cap-and-trade program generally would cap overall greenhouse gas emissions on an economy-wide basis and require major sources of greenhouse gas emissions or major fuel producers to acquire and surrender emission allowances. Carbon taxes could likewise affect us by being based on emissions from our equipment and/or emissions resulting from the use of our products by our customers. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Limitations on greenhouse gas emissions could also adversely affect demand for oil and gas, which could have a material adverse effect on our profitability, financial condition and liquidity.

In 2015, Alberta released a new Climate Leadership Plan. This plan includes implementing an economy-wide carbon price effective in 2017. The plan also includes a legislated limit for oil sands emissions and a methane emission reduction plan which are under development. Regulations are expected to be finalized by 2018. It is expected that these initiatives will create additional costs for the Alberta oil and gas industry. Presently, it is not possible to accurately estimate the costs we could incur to comply with any law or regulations developed.

Our Hedging Activities Limit Participation in Commodity Price Increases and Involve Other Risks

We enter into hedging activities with respect to a portion of our production to manage our exposure to oil, gas and NGL price volatility. To the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may be prevented from fully realizing the benefits of commodity price increases above the prices established by our hedging contracts. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the contract counterparties fail to perform under the contracts. Moreover, as a result of the Dodd-Frank Wall Street Reform and Consumer Protection Act and other legislation, hedging transactions and many of our contract counterparties have come under increasing governmental oversight and regulations in recent years. Although we cannot predict the ultimate impact of these laws and the related rulemaking, some of which is ongoing, existing or future regulations may adversely affect the cost and availability of our hedging arrangements, including by causing our contract counterparties, which are generally financial institutions and other market participants, to curtail or cease their derivatives activities.

The Credit Risk of Our Counterparties Could Adversely Affect Us

We enter into a variety of transactions that expose us to counterparty credit risk. For example, we have exposure to financial institutions and insurance companies through our hedging arrangements, our syndicated revolving credit facility and our insurance policies. Disruptions in the financial markets or otherwise may impact these counterparties and affect their ability to fulfill their existing obligations and their willingness to enter into future transactions with us.

In addition, we are exposed to the risk of financial loss from trade, joint interest billing and other receivables. We sell our oil, gas and NGLs to a variety of purchasers, and, as an operator, we pay expenses and bill our non-operating partners for their respective shares of costs. We also frequently look to buyers of oil and gas properties from us to perform certain obligations associated with the disposed assets, including the removal of production facilities and plugging and abandonment of wells. Certain of these counterparties may experience liquidity problems or other issues and may not be able to meet their financial obligations to us, particularly during a depressed or volatile commodity price environment. Any such default by these counterparties could adversely impact our financial results.

Our Debt May Limit Our Liquidity and Financial Flexibility, and Any Downgrade of Our Credit Rating Could Adversely Impact Us

As of December 31, 2016, we had total consolidated indebtedness of $10.2 billion. Our indebtedness and other financial commitments have important consequences to our business, including, but not limited to:

- requiring us to dedicate a significant portion of our cash flows from operations to debt service payments, thereby limiting our ability to fund working capital, capital expenditures, investments or acquisitions and other general corporate purposes;
- increasing our vulnerability to general adverse economic and industry conditions, including low commodity price environments; and
- limiting our ability to obtain additional financing due to higher costs and more restrictive covenants.

In addition, we receive credit ratings from rating agencies in the U.S. with respect to our debt. Factors that may impact our credit ratings include, among others, debt levels, planned assets sales and purchases, liquidity, forecasted production growth and commodity prices. During 2016, Standard & Poor’s Financial Services and Moody’s Investor Service downgraded our senior unsecured debt ratings. Due to our current credit ratings, we are required to provide letters of credit or other assurances under certain of our contractual arrangements. Further downgrades could adversely impact our ability to access financing and trade credit, require us to provide additional letters of credit or other assurances under contractual arrangements and increase our interest rate under any credit facility borrowing as well as the cost of any other future debt.

Environmental Matters and Related Costs Can Be Significant

As an owner, lessee or operator of oil and gas properties, we are subject to various federal, state, provincial, tribal and local laws and regulations relating to discharge of materials into, and protection of, the environment.

These laws and regulations may, among other things, impose liability on us for the cost of remediating pollution that results from our operations. Environmental laws may impose strict, joint and several liability, and failure to comply with environmental laws and regulations can result in the imposition of administrative, civil or criminal fines and penalties, as well as injunctions limiting operations in affected areas. Any future environmental costs of fulfilling our commitments to the environment are uncertain and will be governed by several factors, including future changes to regulatory requirements. Changes in or additions to public policy regarding the protection of the environment could have a significant impact on our operations and profitability.

Cyber Attacks Targeting Our Systems and Infrastructure May Adversely Impact Our Operations

Our industry has become increasingly dependent on digital technologies to conduct daily operations. Concurrently, the industry has become the subject of increased levels of cyber-attack activity. Cyber attacks often attempt to gain unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data or causing operational disruption and may be carried out by third parties or insiders. The techniques utilized range from highly sophisticated efforts to electronically circumvent network security to more traditional intelligence gathering and social engineering aimed at obtaining information necessary to gain access. Cyber attacks may also be carried out in a manner that does not require gaining unauthorized access, such as by causing denial-of-service attacks. Although we have not suffered material losses related to cyber attacks to date, if we were successfully attacked, we could incur substantial remediation and other costs or suffer other negative consequences. Moreover, as the sophistication of cyber attacks continues to evolve, we may be required to expend significant additional resources to further enhance our digital security or to remediate vulnerabilities.

Limited Control on Properties Operated by Others

Certain of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. We have limited influence and control over the operation or future development of such properties, including compliance with environmental, health and safety regulations or the amount and timing of required future capital expenditures. These limitations and our dependence on the operator and other working interest owners for these properties could result in unexpected future costs and delays, curtailments or cancellations of operations or future development, which could adversely affect our financial condition and results of operations.

Midstream Capacity Constraints and Interruptions Impact Commodity Sales

We rely on midstream facilities and systems to process our gas production and to transport our oil, gas and NGL production to downstream markets. Such midstream systems include EnLink’s systems, as well as other systems operated by us or third parties. Regardless of who operates the midstream systems we rely upon, a portion of our production in any region may be interrupted or shut in from time to time due to losing access to plants, pipelines or gathering systems. Such access could be lost due to a number of factors, including, but not limited to, weather conditions and natural disasters, accidents, field labor issues or strikes. Additionally, we and third parties may be subject to constraints that limit our or their ability to construct, maintain or repair midstream facilities needed to process and transport our production. Such interruptions or constraints could negatively impact our production and associated profitability.

Insurance Does Not Cover All Risks

Our business is hazardous and is subject to all of the operating risks normally associated with the exploration, development, production, processing and transportation of oil, gas and NGLs. Such risks include potential blowouts, cratering, fires, loss of well control, mishandling of fluids and chemicals and possible underground migration of hydrocarbons and chemicals. The occurrence of any of these risks could result in environmental pollution, damage to or destruction of our property, equipment and natural resources, injury to people or loss of life.

To mitigate financial losses resulting from these operational hazards, we maintain comprehensive general liability insurance, as well as insurance coverage against certain losses resulting from physical damages, loss of well control, business interruption and pollution events that are considered sudden and accidental. We also maintain workers' compensation and employer's liability insurance. However, our insurance coverage does not provide 100% reimbursement of potential losses resulting from these operational hazards. Additionally, insurance coverage is generally not available to us for pollution events that are considered gradual, and we have limited or no insurance coverage for certain risks such as political risk and war. Our insurance does not cover penalties or fines assessed by governmental authorities. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our profitability, financial condition and liquidity.

Competition for Assets, Materials, People and Capital Can Be Significant

Strong competition exists in all sectors of the oil and gas industry. We compete with major integrated and independent oil and gas companies for the acquisition of oil and gas leases and properties. We also compete for the equipment and personnel required to explore, develop and operate properties. Typically, during times of rising commodity prices, drilling and operating costs will also increase. During these periods, there is often a shortage of drilling rigs and other oilfield services, which could adversely affect our ability to execute our development plans on a timely basis and within budget. Competition is also prevalent in the marketing of oil, gas and NGLs. Certain of our competitors have financial and other resources substantially greater than ours. They also may have established strategic long-term positions and relationships in areas in which we may seek new entry. As a consequence, we may be at a competitive disadvantage in bidding for assets or services and accessing capital. In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect demand for oil and gas production, such as changing worldwide price and production levels, the cost and availability of alternative fuels and the application of government regulations.

Our Acquisition and Divestiture Activities Involve Substantial Risks

Our business depends, in part, on making acquisitions that complement or expand our current business and successfully integrating any acquired assets or businesses. If we are unable to make attractive acquisitions, our future growth could be limited. Furthermore, even if we do make acquisitions, they may not result in an increase in our cash flow from operations or otherwise result in the benefits anticipated due to various risks, including, but not limited to:

- mistaken estimates or assumptions about reserves, potential drilling locations, revenues and costs, including synergies and the overall costs of equity or debt;
- difficulties in integrating the operations, technologies, products and personnel of the acquired assets or business; and
- unknown and unforeseen liabilities or other issues related to any acquisition for which contractual protections prove inadequate, including environmental liabilities and title defects.

In addition, from time to time, we may sell or otherwise dispose of certain of our properties as a result of an evaluation of our asset portfolio and to help enhance our liquidity. These transactions also have inherent risks, including possible delays in closing, the risk of lower-than-expected sales proceeds for the disposed assets and potential post-closing claims for indemnification. Moreover, volatility in commodity prices may result in fewer potential bidders, unsuccessful sales efforts and a higher risk that buyers may seek to terminate a transaction prior to closing.

Item 1B. ***Unresolved Staff Comments***

Not applicable.

Item 3. *Legal Proceedings*

We are involved in various legal proceedings incidental to our business. However, to our knowledge as of the date of this report, there were no material pending legal proceedings to which we are a party or to which any of our property is subject.

Certain Environmental Matters

Devon Gas Services, L.P., a wholly-owned subsidiary of the Company, is currently in negotiations with the EPA with respect to alleged noncompliance with the leak detection and repair requirements of EPA regulations promulgated under the Clean Air Act at its Beaver Creek Gas Plant located near Riverton, Wyoming. Although management cannot predict the outcome of settlement negotiations, the resolution of this matter may result in a fine or penalty in excess of $100,000.

In addition, in August 2016, we received an information request from the EPA under the Clean Air Act relating to our compliance with certain air emission requirements under Clean Air Act regulations with respect to various locations in our Eagle Ford operations in south Texas. We responded to this information request in November 2016. Given its early stage and the general uncertainty in matters such as these, we are unable to predict the ultimate outcome of this information request, but it may result in the imposition of a fine or penalty, through settlement negotiations or otherwise, in excess of $100,000.

Item 4. *Mine Safety Disclosures*

Not applicable.

PART II

Item 5. *Market for Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

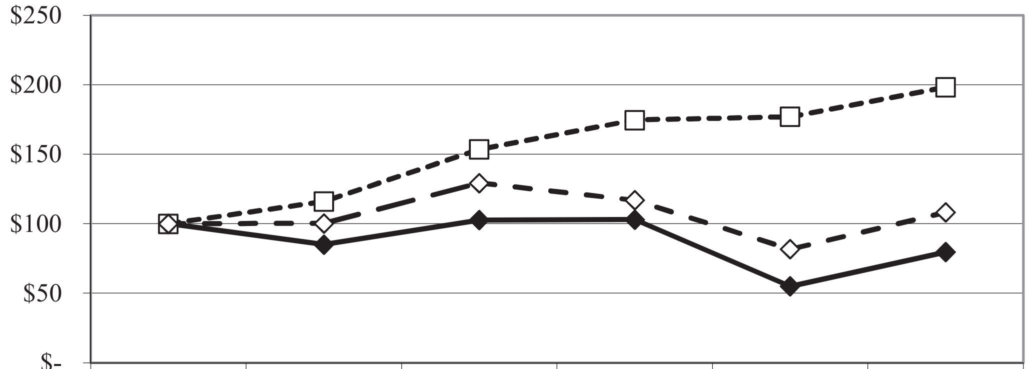
Our common stock is traded on the NYSE. On February 8, 2017, there were 7,856 holders of record of our common stock. We began paying regular quarterly cash dividends on our common stock in the second quarter of 1993. The following table sets forth the quarterly high and low sales prices for our common stock as reported by the NYSE during 2016 and 2015, as well as the quarterly dividends per share paid during 2016 and 2015.

	Price Range of Common Stock		Dividends
	High	Low	Per Share
Quarter Ended 2016:			
December 31, 2016	$ 50.66	$ 36.64	$ 0.06
September 30, 2016	$ 45.62	$ 35.01	$ 0.06
June 30, 2016	$ 39.47	$ 25.55	$ 0.06
March 31, 2016	$ 32.93	$ 18.07	$ 0.24
Quarter Ended 2015:			
December 31, 2015	$ 48.68	$ 28.00	$ 0.24
September 30, 2015	$ 59.80	$ 36.01	$ 0.24
June 30, 2015	$ 70.48	$ 58.77	$ 0.24
March 31, 2015	$ 67.08	$ 56.35	$ 0.24

Performance Graph

The following graph compares the cumulative TSR over a five-year period on Devon's common stock with the cumulative total returns of the S&P 500 Index and a peer group of companies to which we compare our performance. The peer group includes Anadarko Petroleum Corporation, Apache Corporation, Chesapeake Energy Corporation, Concho Resources, Inc., ConocoPhillips, Continental Resources, Inc., Encana Corporation, EOG Resources, Inc., Hess Corporation, Marathon Oil Corporation, Murphy Oil Corporation, Noble Energy, Inc., Occidental Petroleum Corporation and Pioneer Natural Resources Company. The graph was prepared assuming $100 was invested on December 31, 2011 in Devon's common stock, the S&P 500 Index and the peer group, and dividends have been reinvested subsequent to the initial investment.

Comparison of 5-Year Cumulative Total Return
Devon, S&P 500 Index and Peer Group



	2011	2012	2013	2014	2015	2016
Devon	$100.00	$85.06	$102.66	$103.04	$55.02	$79.64
S&P 500	$100.00	$116.00	$153.58	$174.60	$177.01	$198.18
Peer Group	$100.00	$100.19	$129.28	$116.95	$81.69	$108.22

The graph and related information should not be deemed "soliciting material" or to be "filed" with the SEC, nor should such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate such information by reference into such a filing. The graph and information is included for historical comparative purposes only and should not be considered indicative of future stock performance.

Issuer Purchases of Equity Securities

The following table provides information regarding purchases of our common stock that were made by us during the fourth quarter of 2016.

Period	Total Number of Shares Purchased [(1)]	Average Price Paid per Share
October 1 - October 31	25,638	$ 43.29
November 1 - November 30	96,822	$ 42.15
December 1 - December 31	3,778	$ 47.30
Total	126,238	$ 42.54

(1) Share repurchases represent shares received by us from employees for the payment of personal income tax withholding on restricted stock vesting.

Under the Devon Plan, eligible employees may purchase shares of our common stock through an investment in the Devon Stock Fund, which is administered by an independent trustee. Eligible employees purchased approximately 80,600 shares of our common stock in 2016, at then-prevailing stock prices, that they held through their ownership in the Devon Stock Fund. We acquired the shares of our common stock sold under the Devon Plan through open-market purchases.

Similarly, eligible Canadian employees may purchase shares of our common stock through an investment in the Canadian Plan, which is administered by an independent trustee, Sun Life Assurance Company of Canada. Shares sold under the Canadian Plan were acquired through open-market purchases. These shares and any interest in the Canadian Plan were offered and sold in reliance on the exemptions for offers and sales of securities made outside of the U.S., including under Regulation S for offers and sales of securities to employees pursuant to an employee benefit plan established and administered in accordance with the law of a country other than the U.S. In 2016, there were no shares purchased by Canadian employees.

Item 6. *Selected Financial Data*

The financial information below should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data" of this report.

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(Millions, except per share amounts)				
Oil, gas and NGL sales	$ 4,182	$ 5,382	$ 9,910	$ 8,522	$ 7,153
Total revenues and other (1)	$ 12,197	$ 13,145	$ 20,638	$ 10,388	$ 9,514
Earnings (loss) from continuing operations (1)	$ (3,704)	$(15,203)	$ 1,691	$ (20)	$ (185)
Earnings (loss) from continuing operations attributable to Devon (1)	$ (3,302)	$(14,454)	$ 1,607	$ (20)	$ (185)
Earnings (loss) from continuing operations per share attributable to Devon – Basic (1)	$ (6.52)	$ (35.55)	$ 3.93	$ (0.06)	$ (0.47)
Earnings (loss) from continuing operations per share attributable to Devon – Diluted (1)	$ (6.52)	$ (35.55)	$ 3.91	$ (0.06)	$ (0.47)
Cash dividends per common share	$ 0.42	$ 0.96	$ 0.94	$ 0.86	$ 0.80
Weighted average common shares outstanding - Basic	513	412	409	406	404
Weighted average common shares outstanding - Diluted	513	412	411	406	404
Total assets (1)	$ 25,913	$ 29,451	$ 50,568	$ 42,809	$ 43,266
Long-term debt (2)	$ 10,154	$ 12,056	$ 9,761	$ 7,888	$ 8,395
Stockholders' equity	$ 10,375	$ 10,989	$ 26,341	$ 20,499	$ 21,278

(1) Material asset impairments and acquisition and divestiture activity have had significant impacts on operating results and the carrying value of our oil and gas assets over the past few years. More discussion on these items can be found in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 2 and Note 5 of "Item 8. Financial Statements and Supplementary Data" of this report.

(2) Debt balances at December 31, 2016, 2015 and 2014 include $3.3 billion, $3.1 billion and $2.0 billion, respectively, of EnLink debt that is non-recourse to Devon.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Introduction

The following discussion and analysis presents management's perspective of our business, financial condition and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future and should be read in conjunction with "Item 8. Financial Statements and Supplementary Data" of this report.

Overview of 2016 Results

By executing on our strategy outlined in "Items 1 and 2. Business and Properties" of this report, we strive to optimize value for our shareholders by growing cash flow, earnings, production and reserves, all on a per debt-adjusted share basis. Despite the challenges our company and the entire upstream energy sector have faced from the sustained low commodity price environment, we have continued to execute our strategy and position our company for long-term success. Although we have seen moderate improvements in oil and natural gas prices over the course of 2016, prices for oil and natural gas were still significantly lower than 2015 and 2014 and remain under pressure due to excess supply concerns. In response to this environment, we remained committed to an approach centered on:

- Maintaining a balanced portfolio of high-class assets with a focus on value and returns,
- Accelerating our activity in the STACK and Delaware Basin, and preserving continuity in our other U.S. resource plays,
- Driving efficiencies across our portfolio of assets by achieving operating efficiencies and cost savings and increasing capital productivity, and
- Protecting and strengthening our investment-grade balance sheet by investing directionally within cash flow and through use of divestiture proceeds.

To that end, in 2016 we:

- Expanded our position in the STACK by acquiring approximately 80,000 net acres and assets for $1.5 billion, and increased production in this key resource play by 37% compared to 2015;
- Continued the shift to higher-margin products, with oil and bitumen production representing 44% of our retained asset production mix for 2016;
- Successfully divested certain non-core upstream assets in the U.S. and our 50% interest in the Access Pipeline in Canada for $3.1 billion;
- Reduced exploratory and developmental capital investment by approximately 65% compared to 2015;
- Replaced approximately 175% of our retained-asset production through significant reserve additions;
- Reduced G&A and field operating costs by $845 million, or 25%, primarily through cost reduction initiatives, including a workforce reduction in early 2016;
- Reduced Devon debt by $3.1 billion, or 31%, and have no significant long term maturities until 2021;
- Raised net proceeds of $1.5 billion in an offering of our common stock; and
- Exited 2016 with approximately $5 billion in cash and Senior Credit Facility capacity.

In 2017 and beyond, we have the financial capacity to further accelerate investment across our best-in-class U.S. resource plays. We are increasing drilling activity and will continue to rapidly shift our production mix to high-margin products. We will continue our premier technical work to drive capital allocation and efficiency and industry-leading well productivity results. We will continue to maximize the value of our base production by sustaining the operational efficiencies we have achieved. Finally, we will continue to manage activity levels within our cash flows. We expect this disciplined approach will position us to deliver substantial cash flow expansion over the next two years.

In addition, we recognized $267 million of restructuring and transaction costs during 2016 related to the workforce reduction and incurred $5.0 billion of noncash asset impairments as a result of the continued depressed prices for commodities but recognized $1.9 billion in gains on our divestiture transactions. While the gain on divestitures and impairments significantly impacted our earnings, they had no effect on our operating cash flow or debt covenants.

Key measures of our financial performance in 2016 are summarized in the following table:

	Year Ended December 31,				
	2016	Change	2015	Change	2014
	(Millions, except per share and per Boe amounts)				
Net earnings (loss) attributable to Devon	$ (3,302)	+ 77%	$ (14,454)	N/M	$ 1,607
Net earnings (loss) per share attributable to Devon	$ (6.52)	+ 82%	$ (35.55)	N/M	$ 3.91
Core earnings (loss) attributable to Devon [1]	$ (38)	- 104%	$ 1,044	- 48%	$ 2,017
Core earnings (loss) per share attributable to Devon [1]	$ (0.08)	- 103%	$ 2.52	- 49%	$ 4.91
Retained production (MBoe/d)	568	- 4%	589	+13%	521
Total production (MBoe/d)	611	- 10%	680	+1%	673
Realized price per Boe [2]	$ 18.72	- 14%	$ 21.68	- 46%	$ 40.33
Operating cash flow	$ 1,746	- 68%	$ 5,373	- 11%	$ 6,021
Capitalized costs, including acquisitions	$ 4,191	- 33%	$ 6,233	- 54%	$ 13,559
Shareholder and noncontrolling interests distributions	$ 525	- 19%	$ 650	+5%	$ 621
Cash and cash equivalents	$ 1,959	- 15%	$ 2,310	+56%	$ 1,480
Total debt	$ 10,154	- 22%	$ 13,032	+16%	$ 11,193
Reserves (MMBoe)	2,058	- 6%	2,182	- 21%	2,754

(1) Core earnings and core earnings per share attributable to Devon are financial measures not prepared in accordance with GAAP. For a description of core earnings and core earnings per share attributable to Devon, as well as reconciliations to the comparable GAAP measures, see "Non-GAAP Measures" in this Item 7.

(2) Excludes any impact of oil, gas and NGL derivatives.

Our 2016 net loss and net loss per share improved compared to 2015 primarily due to more significant noncash asset impairments recognized in 2015 as a result of the large commodity price declines. Core loss, core loss per share and operating cash flow for 2016 decreased significantly compared to 2015 as a result of the continued decline in commodity prices and the expiration of certain favorable commodity hedging positions.

Business and Industry Outlook

Devon marked its 45th anniversary in the oil and gas business and its 28th year as a public company during 2016. As an established company with a strong leadership team, we have experience operating in periods of challenged commodity prices. With our focused strategy and portfolio of quality assets, we are prepared to successfully navigate the current environment while ensuring our long-term financial strength.

Market prices for crude oil and natural gas are inherently volatile. Therefore, we cannot predict with certainty the future prices for the commodities we produce and sell. During 2016, oil prices ranged from $26.21/Bbl to $54.06/Bbl. As a result of the ongoing worldwide oversupply issue, OPEC agreed to its first oil production cut in eight years in November 2016. Following the agreements by both OPEC and non-OPEC producers to reduce output by nearly 1.8 million barrels per day in the first half of 2017, oil prices jumped approximately 10% in the fourth quarter of 2016, averaging $49.21/Bbl. Current market fundamentals indicate improved prices for crude oil, natural gas and natural gas liquids in 2017; however, changes in OPEC production strategies, the macro-economic environment, geopolitical risks, winter and summer temperature ranges or other factors could impact current forecasts. As such, we anticipate continued volatility into 2017.

While we expect that our industry will remain challenged by relatively low prices for the near-term, we have strategically positioned our company for continued growth and investment in our portfolio of assets. Leveraging the success of our 2016 divestiture program and other key achievements noted above, we are in a position of significant strength and anticipate expanding our exploration and development capital spend by approximately 80% in 2017. Our 2017 outlook is marked by accelerated activity across our key basins, focusing an expanded rig count in the STACK and Delaware Basin and achieving 15% growth in U.S. oil production through some of our best-in-class positions. Additionally, we ramped up our hedging program in 2016, with approximately 50% of our oil and 45% of our gas production hedged entering into 2017.

Finally, EnLink continues to be a strategic advantage for us, allowing for improved midstream growth potential. Annual distributions of approximately $270 million provide a visible cash flow stream to be further invested in our upstream capital programs discussed above.

Results of Operations

Oil, Gas and NGL Production

	Year Ended December 31,				
	2016	Change	2015	Change	2014
Oil (MBbls/d)					
Barnett Shale	1	- 28%	1	- 35%	2
Delaware Basin	33	- 15%	39	+48%	26
Eagle Ford	42	- 37%	66	+65%	40
Heavy Oil	22	- 17%	27	+3%	26
Rockies Oil	14	- 9%	15	+68%	9
STACK	19	+152%	7	+14%	6
Other	10	- 19%	14	- 11%	14
Retained assets	141	- 16%	169	+37%	123
Divested assets	10	- 58%	22	- 34%	35
Total	151	- 21%	191	+20%	158
Bitumen (MBbls/d)					
Heavy Oil	109	+29%	84	+51%	56
Gas (MMcf/d)					
Barnett Shale	741	- 9%	815	- 13%	932
Delaware Basin	91	+25%	73	+9%	67
Eagle Ford	106	- 29%	149	+66%	90
Heavy Oil	20	- 11%	22	- 5%	23
Rockies Oil	25	- 37%	40	- 23%	52
STACK	293	+23%	239	- 1%	242
Other	14	- 16%	17	- 10%	19
Retained assets	1,290	- 5%	1,355	- 5%	1,425
Divested assets	123	- 52%	255	- 49%	495
Total	1,413	- 12%	1,610	- 16%	1,920
NGLs (MBbls/d)					
Barnett Shale	45	- 12%	51	- 12%	58
Delaware Basin	12	+27%	9	+24%	7
Eagle Ford	16	- 33%	25	+113%	12
Rockies Oil	1	- 9%	1	+16%	1
STACK	26	+22%	21	- 7%	23
Other	3	- 17%	3	- 5%	3
Retained assets	103	- 6%	110	+5%	104
Divested assets	13	- 50%	26	- 26%	35
Total	116	- 15%	136	- 2%	139
Combined (MBoe/d)					
Barnett Shale	169	- 10%	188	- 13%	215
Delaware Basin	60	- 1%	61	+35%	45
Eagle Ford	76	- 34%	115	+74%	66
Heavy Oil	134	+17%	115	+34%	86
Rockies Oil	19	- 17%	23	+23%	19
STACK	93	+37%	68	- 2%	70
Other	17	- 13%	19	- 5%	20
Retained assets	568	- 4%	589	+13%	521
Divested assets	43	- 53%	91	- 40%	152
Total	611	- 10%	680	+1%	673

Oil, Gas and NGL Pricing

	Year Ended December 31,				
	2016 [(1)]	Change	2015 [(1)]	Change	2014 [(1)]
Oil (per Bbl)					
U.S.	$ 38.92	- 12%	$ 44.01	- 49%	$ 85.64
Canada	$ 23.96	- 22%	$ 30.58	- 55%	$ 68.14
Total	$ 36.72	- 13%	$ 42.12	- 49%	$ 82.47
Bitumen (per Bbl)					
Canada	$ 19.82	- 15%	$ 23.41	- 58%	$ 55.88
Gas (per Mcf)					
U.S.	$ 1.84	- 15%	$ 2.17	- 45%	$ 3.92
Canada [(2)]	N/M	N/M	N/M	N/M	$ 3.64
Total	$ 1.84	- 14%	$ 2.14	- 45%	$ 3.90
NGLs (per Bbl)					
U.S.	$ 9.81	+5%	$ 9.32	- 62%	$ 24.46
Canada	$ —	N/M	$ —	N/M	$ 50.52
Total	$ 9.81	+5%	$ 9.32	- 63%	$ 24.89
Combined (per Boe)					
U.S.	$ 18.34	- 13%	$ 21.12	- 44%	$ 37.96
Canada	$ 20.07	- 18%	$ 24.46	- 54%	$ 53.11
Total	$ 18.72	- 14%	$ 21.68	- 46%	$ 40.33

(1) Prices presented exclude any effects of oil, gas and NGL derivatives.

(2) The reported Canadian gas volumes include 11, 12 and 21 MMcf/d for the years ended 2016, 2015 and 2014, respectively, that are produced from certain of our leases and then transported to our Jackfish operations where the gas is used as fuel. However, the revenues and expenses related to this consumed gas are eliminated in our consolidated financial results. With the sale of the vast majority of the Canadian gas business in the second quarter of 2014, the eliminated gas revenues subsequently impacted our gas price more significantly.

Commodity Sales

The volume and price changes in the tables above caused the following changes to our oil, gas and NGL sales.

	Oil	Bitumen	Gas	NGLs	Total
			(Millions)		
2014 sales	$ 4,773	$ 1,138	$ 2,737	$ 1,262	$ 9,910
Change due to volumes	976	584	(443)	(23)	1,094
Change due to prices	(2,813)	(1,000)	(1,034)	(775)	(5,622)
2015 sales	$ 2,936	$ 722	$ 1,260	$ 464	$ 5,382
Change due to volumes	(608)	209	(151)	(70)	(620)
Change due to prices	(299)	(143)	(159)	21	(580)
2016 sales	$ 2,029	$ 788	$ 950	$ 415	$ 4,182

Volumes 2016 vs. 2015 Commodity sales decreased due to our 67% reduction in exploration and development capital related to our retained assets during 2016. While expanded drilling in the STACK and the performance of our Jackfish assets drove production increases, these production increases were more than offset by reduced completion activity in the Eagle Ford and natural production declines in the Barnett Shale and Rockies Oil. Delaware Basin production was relatively flat as natural declines offset the increases from new wells. Additionally, our production decreased as a result of our U.S. non-core divestiture program.

Volumes 2015 vs. 2014 Commodity sales increased due to volumes in 2015 because of strong production growth from our U.S. oil properties. The growth was primarily driven by the continued development of our Eagle

Ford, Delaware Basin and Rockies Oil properties. Additionally, our bitumen production increased primarily due to Jackfish 3 coming on-line late in the third quarter of 2014 and reaching nameplate capacity in the third quarter of 2015. Lower royalties resulting from the significant price decrease also increased our heavy oil production. The increases were partially offset by a decrease in our gas production, which resulted primarily from asset divestitures in 2014 and natural reservoir declines.

Prices 2016 vs. 2015 Commodity sales decreased in 2016 as a result of lower prices for oil, bitumen and gas. The decrease in oil and bitumen sales primarily resulted from lower average WTI crude oil index prices, which were approximately 11% lower in 2016 as compared to 2015. The decreases in gas were driven by lower North American regional index prices upon which our gas sales are based. These decreases were partially offset by slightly higher NGL prices at the Mont Belvieu, Texas hub.

Prices 2015 vs. 2014 Commodity sales decreased in 2015 as a result of significantly lower prices for all commodities. The decrease in oil and bitumen sales primarily resulted from significantly lower average WTI crude oil index prices, which were approximately 50% lower in 2015 as compared to 2014. The decreases in gas and NGL sales were driven by lower North American regional index prices upon which our gas sales are based and lower NGL prices at the Mont Belvieu, Texas hub.

Oil, Gas and NGL Derivatives

The following tables provide financial information associated with our oil, gas and NGL hedges. The first table presents the cash settlements and fair value gains and losses recognized as components of our revenues. The subsequent tables present our oil, gas and NGL prices with and without the effects of the cash settlements. The prices do not include the effects of fair value gains and losses.

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
Cash settlements:			
Oil derivatives	$ (41)	$ 2,083	$ 90
Gas derivatives	35	333	(36)
NGL derivatives	(5)	—	1
Total cash settlements	(11)	2,416	55
Gains (losses) on fair value changes:			
Oil derivatives	(103)	(1,687)	1,721
Gas derivatives	(86)	(226)	213
NGL derivatives	(1)	—	—
Total gains (losses) on fair value changes	(190)	(1,913)	1,934
Oil, gas and NGL derivatives	$ (201)	$ 503	$ 1,989

	Year Ended December 31, 2016				
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Boe (Per Boe)
Realized price without hedges	$ 36.72	$ 19.82	$ 1.84	$ 9.81	$ 18.72
Cash settlements of hedges	(0.74)	—	0.07	(0.11)	(0.05)
Realized price, including cash settlements	$ 35.98	$ 19.82	$ 1.91	$ 9.70	$ 18.67

	Year Ended December 31, 2015				
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Boe (Per Boe)
Realized price without hedges	$ 42.12	$ 23.41	$ 2.14	$ 9.32	$ 21.68
Cash settlements of hedges	29.88	—	0.57	—	9.74
Realized price, including cash settlements	$ 72.00	$ 23.41	$ 2.71	$ 9.32	$ 31.42

	Year Ended December 31, 2014				
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Boe (Per Boe)
Realized price without hedges	$ 82.47	$ 55.88	$ 3.90	$ 24.89	$ 40.33
Cash settlements of hedges	1.56	—	(0.05)	0.02	0.22
Realized price, including cash settlements	$ 84.03	$ 55.88	$ 3.85	$ 24.91	$ 40.55

Cash settlements as presented in the tables above represent realized gains or losses related to these various instruments. A summary of our open commodity derivative positions is included in Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report. Our oil, gas and NGL derivatives include price swaps, costless collars and basis swaps.

In addition to cash settlements, we also recognize fair value changes on our oil, gas and NGL derivative instruments in each reporting period. The changes in fair value resulted from new positions and settlements that occurred during each period, as well as the relationships between contract prices and the associated forward curves. Including the cash settlements discussed above, our oil, gas and NGL derivatives incurred a net loss in 2016 and generated net gains in 2015 and 2014.

Marketing and Midstream Revenues and Operating Expenses

	Year Ended December 31,				
	2016	Change	2015	Change	2014
			(Millions)		
Operating revenues	$ 6,323	- 13%	$ 7,260	- 5%	$ 7,667
Product purchases	(5,133)	- 15%	(6,028)	- 8%	(6,540)
Operations and maintenance expenses	(359)	- 8%	(392)	+43%	(275)
Operating profit	$ 831	- 1%	$ 840	- 1%	$ 852
Devon profit (loss)	$ (48)	- 443%	$ 14	- 84%	$ 88
EnLink profit	879	+6%	826	+8%	764
Total profit	$ 831	- 1%	$ 840	- 1%	$ 852

2016 vs. 2015 The overall decrease in marketing and midstream margin during 2016 was primarily due to lower margins on Devon's downstream marketing commitments, offset by EnLink's margin growth largely related to its acquisition activity in late 2015 and the first quarter of 2016. We anticipate the margins on Devon's downstream marketing commitments to continue to negatively impact our marketing and midstream margins into 2017.

2015 vs. 2014 Marketing and midstream operating profit changes were largely driven by a decrease in Devon's marketing activities due to a decrease in commodity prices. These declines were partially offset by a full year of EnLink's legacy asset operations compared to prior year and facility expansions coming online in late 2014, along with assets acquired during 2015.

Asset Dispositions and Other

During 2016, we recognized gains of $1.9 billion in conjunction with the non-core U.S. upstream asset divestitures and the divestiture of our 50% interest in the Access Pipeline in Canada. During 2014, in conjunction with the divestiture of certain Canadian properties, we recognized gains of $1.1 billion. For further discussion, see Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Lease Operating Expenses

	Year Ended December 31,				
	2016	Change	2015	Change	2014
	(Millions, except per Boe amounts)				
LOE:					
U.S.	$ 1,123	- 28%	$ 1,551	- 0%	$ 1,559
Canada	459	- 17%	553	- 28%	773
Total	$ 1,582	- 25%	$ 2,104	- 10%	$ 2,332
LOE per Boe:					
U.S.	$ 6.44	- 14%	$ 7.52	+0%	$ 7.52
Canada	$ 9.36	- 29%	$ 13.18	- 34%	$ 20.10
Total	$ 7.08	- 17%	$ 8.48	- 11%	$ 9.49

2016 vs. 2015 LOE and LOE per Boe decreased during 2016 primarily due to our well optimization and cost reduction initiatives, as well as our non-core oil and gas property divestitures. On an absolute dollar basis, LOE decreased approximately $200 million as a result of our U.S. upstream divestitures, and we anticipate realizing approximately $100 million in additional LOE savings in 2017 as a result of these divestitures. Our cost reduction initiatives have been primarily focused on reducing costs associated with water disposal, power and fuel, compression and workovers. These cost savings were partially offset by $28 million of Access Pipeline transportation tolls which commenced in the fourth quarter of 2016 subsequent to the sale of our interest in Access. Our Access transportation agreement contains a base transportation commitment, which for the initial five years averages $110 million annually.

2015 vs. 2014 LOE per Boe decreased during 2015 primarily as a result of higher Jackfish 3 volumes, our well optimization and cost reduction initiatives, lower royalties and changes in the Canadian to U.S. foreign exchange rate. As Canadian royalties decrease, our net production volumes increase, causing improvements to our per-unit operating costs. The flat U.S. rate is primarily related to our 2014 non-core natural gas asset divestitures and our oil production growth, where projects generate higher margins but generally require a higher cost to produce per unit than our retained and divested gas projects.

General and Administrative Expenses

	Year Ended December 31,				
	2016	Change	2015	Change	2014
			(Millions)		
Gross G&A	$ 853	- 30%	$ 1,210	- 5%	$ 1,272
Capitalized G&A	(244)	- 34%	(372)	- 1%	(376)
Reimbursed G&A	(82)	- 32%	(120)	- 18%	(146)
Devon Net G&A	527	- 27%	718	- 4%	750
EnLink Net G&A	118	- 14%	137	+41%	97
Net G&A	$ 645	- 25%	$ 855	+1%	$ 847

2016 vs. 2015 Gross G&A and capitalized G&A decreased during 2016 largely due to lower Devon employee costs resulting from workforce reductions, as discussed in Note 6 in "Item 8. Financial Statements and Supplementary Data" of this report, and other cost reduction initiatives. Reimbursed G&A decreased primarily due to a reduction in drilling activity in response to the decline in commodity prices as well as the divestiture of operated properties. EnLink net G&A decreased primarily due to lower employee compensation expense and other cost reductions initiatives during 2016.

2015 vs. 2014 Gross G&A decreased during 2015 largely because of a lower employee performance bonus pool and our cost reduction initiatives. Furthermore, $22 million in one-time costs related to the EnLink and GeoSouthern transactions contributed to higher costs in the first quarter of 2014. Reimbursed G&A decreased subsequent to our 2014 asset divestitures. EnLink G&A increased primarily due to a workforce increase associated with EnLink's 2015 acquisitions.

Production and Property Taxes

	Year Ended December 31,				
	2016	Change	2015	Change	2014
			(Millions)		
Production taxes	$ 141	- 29%	$ 198	- 45%	$ 360
Property and other taxes	95	- 37%	151	+3%	147
Devon production and property taxes	236	- 32%	349	- 31%	507
EnLink property taxes	39	- 1%	39	+39%	28
Production and property taxes	$ 275	- 29%	$ 388	- 28%	$ 535
Percentage of oil, gas and NGL sales:					
Production taxes	3.4%	- 8%	3.7%	+1%	3.6%
Property and other taxes	3.2%	- 9%	3.5%	+100%	1.8%
Total	6.6%	- 9%	7.2%	+33%	5.4%

2016 vs. 2015 Production taxes decreased on an absolute dollar basis primarily due to the decrease in our U.S. revenues, on which the majority of our production taxes are assessed. Furthermore, property and other taxes decreased as a result of lower property value assessments from the local taxing authorities across our key operating areas and as a result of our U.S. non-core divestitures. Property taxes do not change in direct correlation with the decline in oil, gas and NGL sales and are generally determined based on the valuation of the underlying assets.

2015 vs. 2014 Production taxes decreased during 2015 primarily because of a decrease in our U.S. revenues, on which the majority of our production taxes are assessed.

Depreciation, Depletion and Amortization

	Year Ended December 31,							
	2016		Change	2015		Change	2014	
	(Millions, except per Boe amounts)							
DD&A:								
Oil and gas properties	$	1,143	- 56%	$	2,580	- 11%	$	2,896
Other assets		145	- 10%		162	+16%		139
Devon DD&A		1,288	- 53%		2,742	- 10%		3,035
EnLink DD&A		504	+30%		387	+36%		284
Total DD&A	$	1,792	- 43%	$	3,129	- 6%	$	3,319
DD&A per Boe:								
Oil and gas properties	$	5.11	- 51%	$	10.40	- 12%	$	11.79

A description of how DD&A of our oil and gas properties is calculated is included in Note 1 in "Item 8. Financial Statements and Supplementary Data" of this report. Generally, when reserve volumes are revised up or down, the DD&A rate per unit of production will change inversely. However, when the depletable base changes, the DD&A rate moves in the same direction. The per unit DD&A rate is not affected by production volumes. Absolute or total DD&A, as opposed to the rate per unit of production, generally moves in the same direction as production volumes.

2016 vs. 2015 DD&A from our oil and gas properties decreased largely because of the significant asset impairments recognized throughout 2015 and 2016. For discussion of asset impairments, see Note 5 in "Item 8. Financial Statements and Supplementary Data" of this report. EnLink's DD&A increased primarily due to EnLink acquisitions in 2016 and 2015.

2015 vs. 2014 DD&A from our oil and gas properties decreased in 2015 compared to 2014 largely because of the 2014 divestitures of certain U.S. and Canadian assets and the oil and gas asset impairments recognized in 2015. EnLink's DD&A increased primarily due to EnLink's acquisitions in 2014 and 2015.

Asset Impairments

During 2016, 2015 and 2014, we recognized asset impairments of $5.0 billion, $20.8 billion and $2.0 billion, respectively. For discussion of asset impairments, see Note 5 in "Item 8. Financial Statements and Supplementary Data" of this report.

Restructuring and Transaction Costs

During 2016, 2015 and 2014, we recognized restructuring and transaction costs of $267 million, $78 million and $46 million, respectively. For discussion of our reorganization programs and the associated restructuring costs, see Note 6 in "Item 8. Financial Statements and Supplementary Data" of this report.

Net Financing Costs

	Year Ended December 31,				
	2016	Change	2015	Change	2014
			(Millions)		
Devon net financing costs:					
Interest based on debt outstanding	$ 488	+9%	$ 450	- 4%	$ 468
Early retirement of debt	269	N/M	—	N/M	48
Capitalized interest	(64)	+18%	(54)	-7%	(58)
Other	21	+50%	14	- 7%	15
Total Devon net financing costs	714	+74%	410	- 13%	473
EnLink net financing costs:					
Interest based on debt outstanding	144	+26%	115	+80%	64
Interest accretion on deferred installment payment	52	N/M	—	N/M	—
Other	(6)	- 25%	(8)	- 27%	(11)
Total EnLink net financing costs	190	+77%	107	+102%	53
Total net financing costs	$ 904	+75%	$ 517	- 2%	$ 526

2016 vs. 2015 Net financing costs increased during 2016 primarily as a result of the retirement premiums and costs related to early redemptions of senior notes in 2016, which is further discussed in Note 14 in "Item 8. Financial Statements and Supplementary Data" of this report. Furthermore, net financing costs increased due to EnLink's fixed rate borrowings and accretion of its future installment payments related to 2016 acquisition activity discussed in Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

2015 vs. 2014 Net financing costs decreased primarily because of the 2014 early retirement premium and costs and a decrease in average fixed-rate borrowings.

Income Taxes

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
Current income tax expense (benefit)	$ 100	$ (237)	$ 477
Deferred income tax expense (benefit)	(273)	(5,828)	1,891
Total income tax expense (benefit)	$ (173)	$ (6,065)	$ 2,368
Effective income tax rate	4%	29%	58%

For discussion on income taxes, see Note 7 in "Item 8. Financial Statements and Supplementary Data" of this report.

Capital Resources, Uses and Liquidity

Sources and Uses of Cash

The following table presents the major source and use categories of our cash and cash equivalents.

	Devon			EnLink			Consolidated		
	2016	2015	2014	2016	2015	2014	2016	2015	2014
					(Millions)				
Operating cash flow	$ 1,080	$ 4,746	$ 5,507	$ 666	$ 627	$ 514	$ 1,746	$ 5,373	$ 6,021
Issuance of common stock	1,469	—	—	—	—	—	1,469	—	—
Divestitures of property and equipment	3,025	106	5,120	93	1	—	3,118	107	5,120
Capital expenditures	(1,667)	(4,735)	(6,192)	(663)	(573)	(796)	(2,330)	(5,308)	(6,988)
Acquisitions of property, equipment and businesses	(849)	(583)	(6,104)	(792)	(524)	(358)	(1,641)	(1,107)	(6,462)
Debt activity, net	(3,383)	770	(2,829)	228	1,061	555	(3,155)	1,831	(2,274)
Shareholder and noncontrolling interests distributions	(221)	(396)	(486)	(304)	(254)	(135)	(525)	(650)	(621)
EnLink and General Partner distributions	265	268	158	(265)	(268)	(158)	—	—	—
EnLink dropdowns	—	167	—	—	(167)	—	—	—	—
Issuance of subsidiary units	—	—	—	892	25	410	892	25	410
Sale of subsidiary units	—	654	—	—	—	—	—	654	—
Effect of exchange rate and other	(64)	(117)	172	139	22	36	75	(95)	208
Net change in cash and cash equivalents	$ (345)	$ 880	$(4,654)	$ (6)	$ (50)	$ 68	$ (351)	$ 830	$(4,586)
Cash and cash equivalents at end of period	$ 1,947	$ 2,292	$ 1,412	$ 12	$ 18	$ 68	$ 1,959	$ 2,310	$ 1,480

Operating Cash Flow

Net cash provided by operating activities continued to be a significant source of capital and liquidity in 2016. Our operating cash flow decreased $3.6 billion, or 68%, during 2016. Throughout 2015, our commodity hedges provided us with $2.4 billion of additional operating cash flow. The majority of these hedges expired in 2015 and were the primary driver of our decrease in operating cash flow in 2016. The remainder of the decrease is primarily related to the continued decrease in commodity prices, partially offset by our focused cost initiatives.

Our operating cash flow decreased 10% during 2015 primarily due to lower commodity prices. The effects of lower commodity prices were partially offset by the collection of $425 million of income taxes receivable in the first quarter of 2015 and $2.4 billion of cash settlements associated with our commodity derivatives during 2015.

Excluding payments made for acquisitions, our consolidated operating cash flow funded 75%, 100% and 86% of our capital expenditures during 2016, 2015 and 2014, respectively. In 2016, 2015 and 2014, leveraging our liquidity and other capital resources, we also used cash balances, short-term debt, proceeds from EnLink transactions and divestiture proceeds to fund our acquisitions, dividends and capital requirements.

Issuance of Common Stock

In February 2016, we issued 79 million shares of our common stock to the public, inclusive of 10 million shares sold as part of the underwriters' option. Net proceeds from the offering were approximately $1.5 billion.

Divestitures of Property and Equipment

During 2016, we divested certain non-core upstream assets in the U.S. and our 50% interest in the Access Pipeline in Canada for approximately $3.0 billion, net of purchase price adjustments. Proceeds from these divestitures were used primarily for debt repayment and to support capital investment in Devon's core resource plays. We did not have significant current cash income taxes resulting from these divestitures. For further discussion, see Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

During 2014, we divested certain non-core upstream assets in the U.S. and Canada for approximately $5.1 billion. These proceeds were used primarily for debt repayment relating to the GeoSouthern transaction. For additional discussion, see Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Capital Expenditures

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
Oil and gas	$ 1,624	$ 4,577	$ 5,735
Corporate and other	43	158	457
Devon capital expenditures	1,667	4,735	6,192
EnLink capital expenditures	663	573	796
Total capital expenditures	$ 2,330	$ 5,308	$ 6,988
Devon acquisitions	$ 849	$ 583	$ 6,104
EnLink acquisitions	792	524	358
Total acquisitions	$ 1,641	$ 1,107	$ 6,462

Capital expenditures consist of amounts related to our oil and gas exploration and development operations, our midstream operations, other corporate activities and EnLink growth and maintenance activities. The vast majority of our capital expenditures are for the acquisition, drilling and development of oil and gas properties. In response to our lower operating cash flow, Devon's 2016 capital program was designed to be lower than 2015. This change is evidenced by a 56% decrease in total capital expenditures from 2015 to 2016, excluding acquisitions. Since 2014, we have reduced our capital expenditures by approximately 70%.

Capital expenditures for Devon's and EnLink's midstream operations are primarily for the construction and expansion of oil and gas gathering facilities and pipelines. Midstream capital expenditures are largely impacted by oil and gas drilling and development activities.

Acquisition capital in 2016 primarily consisted of Devon's bolt-on acquisition of assets in the STACK play for $1.5 billion and EnLink's acquisition of Anadarko Basin gathering and processing midstream assets for $1.5 billion. Approximately $849 million and $792 million, respectively, was paid in cash at the closings with the remainder of the purchase prices funded with equity consideration and debt. In 2015 our acquisition activity primarily consisted of the Powder River Basin asset acquisition in the fourth quarter. The majority of the acquisition capital in 2014 related to the GeoSouthern acquisition in the Eagle Ford. EnLink's acquisitions in 2015 and 2014 consisted of additional oil and gas pipeline assets, including gathering, transportation and processing facilities. For further discussion on acquisition activity, see Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Debt Activity, Net

During 2016, our consolidated net debt decreased $2.9 billion. The decrease was primarily due to completed tender offers to purchase and redeem $2.1 billion of debt securities prior to their maturity and a $1 billion reduction in short-term borrowings during 2016. In conjunction with the tender offers, we recognized a $269 million loss on the early retirement of debt, including $265 million of cash retirement costs and fees. The decrease was partially offset by $229 million of net borrowings from EnLink. For additional information, see Note 14 in "Item 8. Financial Statements and Supplementary Data" in this report.

During 2015, our consolidated net debt increased $1.8 billion. In June 2015, we issued $750 million of 5.0% senior notes. We used these proceeds to repay the aggregate principal amount of our floating rate senior notes upon maturity on December 15, 2015, as well as outstanding commercial paper balances. In December 2015, we issued $850 million of 5.85% senior notes to fund acquisitions announced in the fourth quarter. EnLink's net debt borrowings increased $1.1 billion primarily from borrowings made to fund acquisitions and dropdowns.

During 2014, we decreased our net debt by $2.2 billion. The decrease was primarily related to the repayment of debt used to fund the GeoSouthern transaction. This was partially offset by $555 million of net borrowings from EnLink to fund its operations.

Shareholder and Noncontrolling Interests Distributions

The following table summarizes our common stock dividends.

	Amounts (Millions)	Rate (Per Share)
Year Ended 2016:		
First quarter 2016	$ 125	$ 0.24
Second quarter 2016	33	$ 0.06
Third quarter 2016	32	$ 0.06
Fourth quarter 2016	31	$ 0.06
Total year-to-date	$ 221	
Year Ended 2015:		
First quarter 2015	$ 99	$ 0.24
Second quarter 2015	98	$ 0.24
Third quarter 2015	99	$ 0.24
Fourth quarter 2015	100	$ 0.24
Total year-to-date	$ 396	
Year Ended 2014:		
First quarter 2014	$ 90	$ 0.22
Second quarter 2014	99	$ 0.24
Third quarter 2014	98	$ 0.24
Fourth quarter 2014	99	$ 0.24
Total year-to-date	$ 386	

In response to the depressed commodity price environment, we reduced our quarterly dividend to $0.06 per share in the second quarter of 2016.

In conjunction with the formation of EnLink in the first quarter of 2014, we made a payment of $100 million to noncontrolling interests. Furthermore, EnLink and the General Partner distributed $304 million, $254 million and $135 million to non-Devon unitholders during 2016, 2015 and 2014, respectively.

EnLink and General Partner Distributions

Devon received $265 million, $268 million and $158 million in distributions from EnLink and the General Partner during 2016, 2015 and 2014, respectively.

EnLink Dropdowns

In the second quarter of 2015, Devon received $167 million in cash from EnLink in exchange for VEX. For further discussion, see Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Issuance of Subsidiary Units

In January 2016, to fund a portion of the cash consideration of its acquisition of Anadarko Basin gathering and processing midstream assets, EnLink issued 50 million preferred units in a private placement generating cash proceeds of approximately $725 million. General Partner common units were also issued as consideration in the transaction.

During 2016, 2015 and 2014, EnLink issued and sold approximately 10.0 million, 1.3 million and 14.8 million common units through general public offerings and its "at the market" equity program, generating net proceeds of approximately $167 million, $25 million and $410 million, respectively.

Sale of Subsidiary Units

In early 2015, we conducted an underwritten secondary public offering of 26.2 million common units representing limited partner interests in EnLink, raising proceeds of $654 million, net of underwriting discount. See Note 18 in "Item 8. Financial Statements and Supplementary Data" of this report.

Effect of Exchange Rate and Other

In 2016, EnLink received contributions from noncontrolling interests. For further discussion see Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Liquidity

Historically, our primary sources of capital and liquidity have been our operating cash flow, asset divestiture proceeds and cash on hand. Additionally, we maintain a commercial paper program, supported by our revolving line of credit, which can be accessed as needed to supplement operating cash flow and cash balances. Available sources of capital and liquidity include, among other things, debt and equity securities that can be issued pursuant to our shelf registration statement filed with the SEC, as well as the sale of a portion of our common units representing interests in our investment in EnLink and the General Partner. The most significant source of liquidity in 2016 has come from approximately $3.0 billion of proceeds related to our asset divestitures. We estimate the combination of these sources of capital will continue to be adequate to fund our planned capital expenditures, future debt repayments and other contractual commitments as discussed in this section.

Operating Cash Flow

Our operating cash flow is sensitive to many variables, the most volatile of which are the prices of the oil, bitumen, gas and NGLs we produce and sell. Our consolidated operating cash flow decreased 68% in 2016 as a result of the expiration of certain favorable commodity hedging positions and the continued decrease in commodity prices. In spite of this decline, we expect operating cash flow to continue to be a primary source of liquidity as we adjust our capital program in response to lower commodity prices. Additionally, we anticipate utilizing our credit availability to provide additional liquidity as needed.

Commodity Prices – Prices are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors, which are difficult to predict, create volatility in prices and are beyond our control. As a result, entering into 2017 we have hedged approximately 50% of our oil and 45% of our gas production. The key terms to our oil, gas and NGL derivative financial instruments as of December 31, 2016 are presented in Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report.

Commodity prices can also affect our operating cash flow through an indirect effect on operating expenses. Significant commodity price decreases can lead to a decrease in drilling and development activities. As a result, the demand and cost for people, services, equipment and materials may also decrease, causing a positive impact on our cash flow as the prices paid for services and equipment decline. However, the inverse is also generally true during periods of rising commodity prices.

Interest Rates – Our operating cash flow can also be impacted by interest rate fluctuations. As of December 31, 2016, we had total debt of $10.2 billion. Of this amount, $10.0 billion bears fixed interest rates averaging 5.3%, and approximately $150 million is comprised of floating rate debt with interest rates averaging 2.5%.

As of December 31, 2016, we had open interest rate swap positions that are presented in Note 3 in "Item 8. Financial Statements and Supplementary Data" in this report.

Credit Losses – Our operating cash flow is also exposed to credit risk in a variety of ways. This includes the credit risk related to customers who purchase our oil, gas and NGL production, the collection of receivables from our joint-interest partners for their proportionate share of expenditures made on projects we operate and counterparties to our derivative financial contracts. We utilize a variety of mechanisms to limit our exposure to the credit risks of our customers, partners and counterparties. Such mechanisms include, under certain conditions, requiring letters of credit, prepayments or collateral postings.

As recent years indicate, we have a history of investing more than 100% of our operating cash flow into capital development activities to grow our company and maximize value for our shareholders. Therefore, negative movements in any of the variables discussed above would not only impact our operating cash flow but also would likely impact the amount of capital investment we could or would make. In the current environment, assuming current pricing expectations, our 2017 exploration and development capital budget is expected to be approximately $2.0 billion to $2.3 billion.

At the end of 2016, we held approximately $2.0 billion of cash. Included in this total was $644 million of cash held by our foreign subsidiaries. If we were to repatriate a portion or all of the cash held by our foreign subsidiaries, we would recognize and pay current income taxes in accordance with current U.S. tax law. The payment of such additional income tax would decrease the amount of cash ultimately available to fund our business.

Credit Availability

We have a $3.0 billion Senior Credit Facility. The maturity date for $30 million of the Senior Credit Facility is October 24, 2017. The maturity date for $164 million of the Senior Credit Facility is October 24, 2018. The maturity date for the remaining $2.8 billion is October 24, 2019. This credit facility supports our $3.0 billion of short-term credit under our commercial paper program. As of December 31, 2016, there were no borrowings under our commercial paper program. See Note 14 in "Item 8. Financial Statements and Supplementary Data" of this report for further discussion.

The Senior Credit Facility contains only one material financial covenant. This covenant requires us to maintain a ratio of total funded debt to total capitalization, as defined in the credit agreement, of no more than 65%. The credit agreement defines total funded debt as funds received through the issuance of debt securities such as debentures, bonds, notes payable, credit facility borrowings and short-term commercial paper borrowings. In addition, total funded debt includes all obligations with respect to payments received in consideration for oil, gas and NGL production yet to be acquired or produced at the time of payment. Funded debt excludes our outstanding letters of credit and trade payables. The credit agreement defines total capitalization as the sum of funded debt and stockholders' equity adjusted for noncash financial write-downs, such as full cost ceiling and goodwill impairments. As of December 31, 2016, we were in compliance with this covenant. Our debt-to-capitalization ratio at December 31, 2016, as calculated pursuant to the terms of the agreement, was 18.7%.

Our access to funds from the Senior Credit Facility is not restricted under any "material adverse effect" clauses. It is not uncommon for credit agreements to include such clauses. These clauses can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have a material and adverse effect on the borrower's financial condition, operations, properties or business considered as a whole, the borrower's ability to make timely debt payments or the enforceability of material terms of the credit agreement. While our credit facility includes covenants that require us to report a condition or event having a material adverse effect, the obligation of the banks to fund the credit facility is not conditioned on the absence of a material adverse effect.

As market conditions warrant and subject to our contractual restrictions, liquidity position and other factors, we may from time to time seek to repurchase or retire our outstanding debt through cash purchases and/or exchanges for other debt or equity securities in open market transactions, privately negotiated transactions, by tender offer or otherwise. Any such cash repurchases by us may be funded by cash on hand or incurring new debt. The amounts involved in any such transactions, individually or in the aggregate, may be material. Furthermore, any such repurchases or exchanges may result in our acquiring and retiring a substantial amount of such indebtedness, which would impact the trading liquidity of such indebtedness.

Debt Ratings

We receive debt ratings from the major ratings agencies in the U.S. In determining our debt ratings, the agencies consider a number of qualitative and quantitative items including, but not limited to, commodity pricing levels, our liquidity, asset quality, reserve mix, debt levels, cost structure, planned asset sales and near-term and long-term production growth opportunities. In February 2016, our credit rating was revised by Standard & Poor's Financial Services from BBB+ with a negative outlook to BBB with a stable outlook, and Moody's Investor Service revised our senior unsecured rating from Baa1 with a stable outlook to Ba2 with negative outlook. In March 2016, Fitch Ratings affirmed our BBB+ rating but revised our outlook from stable to negative. Further, in July 2016, Moody's revised the outlook to stable. The downgrade in ratings required us to post letters of credit and cash collateral as financial assurance of performance under certain contractual arrangements. Any further rating downgrades may result in additional letters of credit or cash collateral being posted under certain contractual arrangements.

There are no "rating triggers" in any of our or EnLink's contractual debt obligations that would accelerate scheduled maturities should our debt rating fall below a specified level. However, these downgrades could adversely impact our and EnLink's interest rate on any credit facility borrowings and the ability to economically access debt markets in the future.

Capital Expenditures

Excluding EnLink, our 2017 capital expenditures are expected to range from $2.3 billion to $2.7 billion, including $2.0 billion to $2.3 billion for our exploration and development capital program. To a certain degree, the ultimate timing of these capital expenditures is within our control. Therefore, if commodity prices fluctuate from our current estimates, we could choose to defer a portion of these planned 2017 capital expenditures until later periods or accelerate capital expenditures planned for periods beyond 2017 to achieve the desired balance between sources and uses of liquidity. Based upon current price expectations for 2017, available cash balances and credit availability, we anticipate having adequate capital resources to fund our 2017 capital expenditures.

EnLink Liquidity

EnLink has a $1.5 billion unsecured revolving credit facility. The General Partner has a $250 million revolving credit facility. As of December 31, 2016, there were $12 million in outstanding letters of credit and $120 million borrowed under the $1.5 billion credit facility and $28 million outstanding borrowings under the $250 million credit facility. All of EnLink's and the General Partner's debt is non-recourse to Devon.

EnLink's 2017 capital budget includes approximately \$610 million to \$770 million of identified growth projects. EnLink's primary capital projects for 2017 include construction of the Lobo II plant and gathering system in the Delaware Basin, completing construction of an NGL pipeline in Louisiana and development of its Tall Oak assets.

EnLink expects to fund the growth capital expenditures from the proceeds of borrowings under its bank credit facility and proceeds from other debt and equity sources. EnLink expects to fund its 2017 maintenance capital expenditures from operating cash flows. EnLink employs a strategy that includes maintaining stable operating cash flows that are supported by long-term, fixed-fee contracts. Approximately 97% of EnLink's cash flows were generated from fee-based services in 2016. In 2017, it is possible that not all of the planned projects will be commenced or completed. EnLink's ability to pay distributions to its unitholders, fund planned capital expenditures and make acquisitions will depend upon its future operating performance, which will be affected by prevailing economic conditions in the industry and financial, business and other factors, some of which are beyond its control.

Contractual Obligations

The following table presents a summary of our contractual obligations as of December 31, 2016.

	Payments Due by Period				
	Total	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
			(Millions)		
Devon obligations:					
Debt [1]	\$ 6,933	\$ —	\$ 277	\$ 500	\$ 6,156
Interest expense [2]	6,579	390	771	752	4,666
Purchase obligations [3]	2,949	609	1,411	929	—
Operational agreements [4]	4,726	545	914	600	2,667
Operational agreements with EnLink [5]	1,589	600	847	142	—
Asset retirement obligations [6]	1,258	46	143	163	906
Drilling and facility obligations [7]	388	76	133	94	85
Lease obligations [8]	371	50	168	98	55
Other [9]	202	202	—	—	—
Total Devon obligations	24,995	2,518	4,664	3,278	14,535
EnLink obligations:					
Debt [1]	3,311	—	428	120	2,763
Interest expense [2]	1,966	144	283	267	1,272
Other [9]	794	313	334	35	112
Total EnLink obligations	6,071	457	1,045	422	4,147
Total obligations	\$ 31,066	\$ 2,975	\$ 5,709	\$ 3,700	\$ 18,682

(1) Debt amounts represent scheduled maturities of debt obligations at December 31, 2016, excluding net discounts and debt issue costs included in the carrying value of debt.

(2) Interest expense represents the scheduled cash payments on long-term fixed-rate debt.

(3) Purchase obligation amounts represent contractual commitments primarily to purchase condensate at market prices for use at our heavy oil projects in Canada. We have entered into these agreements because condensate is an integral part of the heavy oil transportation process. Any disruption in our ability to obtain condensate could negatively affect our ability to transport heavy oil at these locations. Our total obligation related to condensate purchases expires in 2021. The value of the obligation in the table above is based on the contractual volumes and our internal estimate of future condensate market prices.

(4) Operational agreements represent commitments to transport or process certain volumes of oil, gas and NGLs for a fixed fee. We have entered into these agreements to aid the movement of our production to downstream markets.

(5) Operational agreements between Devon and EnLink represent fixed-fee gathering and processing and transportation agreements. These agreements also include minimum volume commitments that will remain in effect for approximately two more years, as well as annual rate escalators.
(6) Asset retirement obligations represent estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These obligations are recorded as liabilities on our December 31, 2016 balance sheet.
(7) Drilling and facility obligations represent gross contractual agreements with third-party service providers to procure drilling rigs and other related services for developmental and exploratory drilling and facilities construction.
(8) Lease obligations consist primarily of non-cancelable leases for office space and equipment used in our daily operations.
(9) Other Devon obligations primarily relate to uncertain tax positions as discussed in Note 7 in "Item 8. Financial Statements and Supplementary Data" of this report. Other EnLink obligations primarily consist of $500 million of future installment payments on the Tall Oak acquisition as discussed in Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Contingencies and Legal Matters

For a detailed discussion of contingencies and legal matters, see Note 19 in "Item 8. Financial Statements and Supplementary Data" of this report.

Critical Accounting Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the U.S. requires us to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known. We consider the following to be our most critical accounting estimates that involve judgment and have reviewed these critical accounting estimates with the Audit Committee of our Board of Directors.

Full Cost Method of Accounting and Proved Reserves

Our estimates of proved reserves are a major component of the depletion and full cost ceiling calculations. Additionally, our proved reserves represent the element of these calculations that require the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil, gas and NGL reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data. Our engineers prepare our reserve estimates. We then subject certain of our reserve estimates to audits performed by third-party petroleum consulting firms. In 2016, 89% of our reserves were subjected to such audits.

The passage of time provides more qualitative information regarding estimates of reserves, when revisions are made to prior estimates to reflect updated information. In the past five years, annual performance revisions to our reserve estimates, which have been both increases and decreases in individual years, have averaged less than 5% of the previous year's estimate. However, there can be no assurance that more significant revisions will not be necessary in the future. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

While the quantities of proved reserves require substantial judgment, the associated prices of oil, gas and NGL reserves, and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. Applicable rules require future net revenues to be calculated using prices that represent the average of the first-day-of-the-month price for the 12-month period prior to the end of each quarterly period. Such rules also dictate that a 10% discount factor be used. Therefore, the discounted future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs or our enterprise risk.

Because the ceiling calculation dictates the use of prices that are not representative of future prices and requires a 10% discount factor, the resulting value is not indicative of the true fair value of the reserves. Oil and gas prices have historically been cyclical and, for any particular 12-month period, can be either higher or lower than our long-term price forecast, which is a more appropriate input for estimating fair value. Therefore, oil and gas property write-downs that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Because of the volatile nature of oil and gas prices, it generally is not possible to predict the timing or magnitude of full cost write-downs. In addition, because of the inter-relationship of the various judgments made to estimate proved reserves, it is impractical to provide quantitative analyses of the effects of potential changes in these estimates. However, decreases in estimates of proved reserves would generally increase our depletion rate and, thus, our depletion expense. Decreases in our proved reserves may also increase the likelihood of recognizing a full cost ceiling write-down.

Based on prices from the last nine months of 2016 and the short-term pricing outlook for the first quarter of 2017, we do not expect to recognize U.S. and Canadian full cost impairments in the first quarter of 2017.

Derivative Financial Instruments

We enter into derivative financial instruments with respect to a portion of our oil, gas and NGL production to hedge future prices received. Additionally, EnLink periodically enters into derivative financial instruments with respect to its oil, gas and NGL marketing activity. These commodity derivative financial instruments include financial price swaps, basis swaps, costless price collars and call options.

The estimates of the fair values of our derivative instruments require substantial judgment. We estimate the fair values of our commodity derivative financial instruments primarily by using internal discounted cash flow calculations. The most significant variable to our cash flow calculations is our estimate of future commodity prices. We base our estimate of future prices upon published forward commodity price curves such as the Inside FERC Henry Hub forward curve for gas instruments and the NYMEX WTI forward curve for oil instruments. Another key input to our cash flow calculations is our estimate of volatility for these forward curves, which we base primarily upon implied volatility. The resulting estimated future cash inflows or outflows over the lives of the contracts are discounted primarily using U.S. Treasury bill rates. These pricing and discounting variables are sensitive to the period of the contract and market volatility as well as changes in forward prices and regional price differentials.

We periodically enter into interest rate swaps to manage our exposure to interest rate volatility. We estimate the fair values of our interest rate swap financial instruments primarily by using internal discounted cash flow calculations based upon forward interest rate yields. The most significant variable to our cash flow calculations is our estimate of future interest rate yields. We base our estimate of future yields upon our own internal model that utilizes forward curves such as the LIBOR or the Federal Funds Rate provided by third parties. The resulting estimated future cash inflows or outflows over the lives of the contracts are discounted using the LIBOR and money market futures rates. These yield and discounting variables are sensitive to the period of the contract and market volatility.

We periodically enter into foreign exchange forward contracts to manage our exposure to fluctuations in exchange rates. Under the terms of our foreign exchange forward contracts, we generally receive U.S. dollars and pay Canadian dollars based on a total notional amount. We estimate the fair values of our foreign exchange forward contracts primarily by using internal discounted cash flow calculations based upon forward exchange rates. The most significant variable to our cash flow calculations is our observation of forward foreign exchange rates. The resulting future cash inflows or outflows at maturity of the contracts are discounted using Treasury rates. These discounting variables are sensitive to the period of the contract and market volatility.

We periodically validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties.

Counterparty credit risk has not had a significant effect on our cash flow calculations and derivative valuations. This is primarily the result of two factors. First, we have mitigated our exposure to any single counterparty by contracting with numerous counterparties. Our oil, gas and NGL commodity derivative contracts are held with thirteen separate counterparties. Second, our derivative contracts generally require cash collateral to be posted if either our or the counterparty's credit rating falls below certain credit rating levels.

Because we have chosen not to qualify our derivatives for hedge accounting treatment, changes in the fair values of derivatives can have a significant impact on our reported results of operations. Generally, changes in derivative fair values will not impact our liquidity or capital resources.

Settlements of derivative instruments, regardless of whether they qualify for hedge accounting, do have an impact on our liquidity and results of operations. Generally, if actual market prices are higher than the price of the derivative instruments, our net earnings and cash flow from operations will be lower relative to the results that would have occurred absent these instruments. The opposite is also true. Additional information regarding the effects that changes in market prices can have on our derivative financial instruments, net earnings and cash flow from operations is included in "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" of this report.

Business Combinations

Accounting for the acquisition of a business requires the assets and liabilities of the acquired business to be recorded at fair value. Deferred taxes are recorded for any differences between the fair value and the tax basis of the acquired assets and liabilities. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill.

There are various assumptions we make in determining the fair values of an acquired company's assets and liabilities. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of the oil and gas properties acquired. To determine the fair values of these properties, we prepare estimates of oil, natural gas and NGL reserves. These estimates are based on work performed by our engineers and that of outside consultants. The judgments associated with these estimated reserves are described earlier in this section in connection with the full cost ceiling calculation.

However, there are factors involved in estimating the fair values of acquired oil, natural gas and NGL properties that require more judgment than that involved in the full cost ceiling calculation. As stated above, the full cost ceiling calculation applies a historical 12-month average price to the reserves to arrive at the ceiling amount. By contrast, the fair value of reserves acquired in a business combination must be based on our estimates of future oil, natural gas and NGL prices. Our estimates of future prices are based on our own analysis of pricing trends. These estimates are based on current data obtained with regard to regional and worldwide supply and demand dynamics such as economic growth forecasts. They are also based on industry data regarding natural gas storage availability, drilling rig activity, changes in delivery capacity, trends in regional pricing differentials and other fundamental analysis. Forecasts of future prices from independent third parties are noted when we make our pricing estimates.

We estimate future prices to apply to the estimated reserve quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues are then discounted using a rate determined appropriate at the time of the business combination based upon our cost of capital.

We also apply these same general principles to estimate the fair value of unproved properties acquired in a business combination. These unproved properties generally represent the value of probable and possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net revenues of probable and possible reserves are reduced by what we consider to be an appropriate risk-weighting factor in each particular instance.

In addition, our acquisitions have involved other entities whose operations included substantial midstream activities. In these transactions, the purchase price is allocated to the fair value of midstream facilities and equipment, generally consisting of processing facilities and pipeline systems. Estimating the fair value of these assets requires certain assumptions to be made regarding future quantities of commodities estimated to be processed and transported through these facilities and pipelines, as well as estimates of future expected prices and operating and capital costs.

Goodwill

We test goodwill for impairment annually at October 31, or more frequently if events or changes in circumstances dictate that the carrying value of goodwill may not be recoverable. While we use data as of October 31 for our test, we typically complete the test in late December or early January as the October 31 market data used in our test becomes available. We first assess the qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. If we determine that it is more likely than not that its fair value is less than its carrying amount, then the two-step goodwill impairment test is performed.

In the first step of the impairment test, the fair value of a reporting unit is compared to its carrying value. Because quoted market prices are not available for our reporting units, the fair values of the reporting units are estimated based upon several valuation analyses, including comparable companies, comparable transactions and premiums paid. If the carrying value of a reporting unit exceeds its fair value, the second step of the impairment test is performed for purposes of measuring the impairment. In the second step, the fair value of the reporting unit is allocated to all of the assets and liabilities of the reporting unit to determine an implied goodwill value. This allocation is similar to a purchase price allocation. If the carrying amount of the reporting unit's goodwill exceeds the implied fair value of goodwill, an impairment loss is recognized in an amount equal to that excess. The determination of fair value requires judgment and involves the use of significant estimates and assumptions about expected future cash flows derived from internal forecasts and the impact of market conditions on those assumptions. Critical assumptions primarily include revenue growth rates driven by future commodity prices and volume expectations, operating margins and capital expenditures.

For the October 31, 2016 impairment tests for Devon's U.S. reporting unit and each of EnLink's reporting units, step one of the impairment analyses showed that the fair value of each reporting unit exceeded its carrying value.

Sustained weakness in the overall energy sector driven by low commodity prices, together with a decline in the EnLink unit price, caused a change in circumstances warranting an interim impairment test for EnLink's reporting units in the first quarter of 2016. Using the fair value approaches described above, in the first quarter of 2016 it was determined that the estimated fair value of EnLink's Texas, General Partner and Crude and Condensate reporting units were less than their carrying amounts, primarily due to changes in assumptions related to commodity prices and discount rates. Through the analysis, a goodwill impairment loss of $473 million, $307 million and $93 million for EnLink's Texas, General Partner and Crude and Condensate reporting units, respectively, was recognized in the first quarter of 2016.

As of March 31, 2016, the goodwill allocated to the Crude and Condensate reporting unit was fully impaired. Other than those mentioned above, no other goodwill impairment was identified or recorded for the remaining reporting units as a result of the interim goodwill assessment, as their estimated fair values were in excess of carrying values. However, the fair value of EnLink's Texas and General Partner reporting units are not substantially in excess of their carrying value. The fair value of the Texas and General Partner reporting units approximates their carrying values after considering the impairment loss above, and as of December 31, 2016, $233 million and $1.1 billion of goodwill remains allocated to the reporting units, respectively.

Our impairment determinations involved significant assumptions and judgments, as discussed above. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. If actual future results are not consistent with these assumptions and estimates, or the assumptions and estimates change due to new information, we may be exposed to additional goodwill impairment charges, which would be recognized in the period in which we would determine that the carrying value exceeds fair value. We would expect that a prolonged or sustained period of lower commodity prices would adversely affect the estimate of future operating results, which could result in future goodwill impairments for other reporting units due to the potential impact on the cash flows of our operations.

The impairment of goodwill has no effect on liquidity or capital resources. However, it adversely affects our results of operations in the period recognized.

Other Intangible Assets

In 2015, the assessment of customer relationships was updated due to the factors described in the aforementioned goodwill section. This assessment resulted in a $223 million impairment of other intangible assets related to EnLink's Crude and Condensate reporting unit. Level 3 fair value measurements were utilized for the impairment analysis of definite-lived intangible assets, which included discounted cash flow estimates, consistent with those utilized in the goodwill impairment assessment.

The other intangible assets impairment has no effect on liquidity or capital resources. However, it adversely affects our results of operations in the period recognized.

Income Taxes

The amount of income taxes recorded requires interpretations of complex rules and regulations of federal, state, provincial and foreign tax jurisdictions. We recognize current tax expense based on estimated taxable income for the current period and the applicable statutory tax rates. We routinely assess potential uncertain tax positions and, if required, estimate and establish accruals for such amounts. We have recognized deferred tax assets and liabilities for temporary differences, operating losses and other tax carryforwards. We routinely assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized. At the end of 2016 and 2015, we had deferred tax assets that largely resulted from the full cost impairments recognized throughout 2015 and 2016. As a result of our recent cumulative losses and our current realization assessment, we recorded a 100% valuation allowance against our U.S. deferred tax assets as of December 31, 2016 and December 31, 2015. Further, in 2016, we recorded a $69 million valuation allowance against certain Canadian deferred tax assets as a result of continued financial losses.

The accruals for deferred tax assets and liabilities are often based on assumptions that are subject to a significant amount of judgment by management. These assumptions and judgments are reviewed and adjusted as facts and circumstances change. Material changes to our income tax accruals may occur in the future based on the progress of ongoing audits, changes in legislation or resolution of pending matters.

We also assess factors relative to whether our foreign earnings are considered indefinitely reinvested. These factors include forecasted and actual results for both our U.S. and Canadian operations, borrowing conditions in the U.S. and existing U.S. income tax laws, particularly the laws pertaining to the deductibility of intangible drilling costs and repatriations of foreign earnings. Changes in any of these factors could require recognition of additional deferred, or even current, U.S. income tax expense. We accrue deferred U.S. income tax expense on our foreign earnings when the factors indicate that these earnings are no longer considered indefinitely reinvested.

For our foreign earnings deemed indefinitely reinvested, we do not calculate a hypothetical deferred tax liability on these earnings. Calculating a hypothetical tax on these accumulated earnings is much different from the calculation of the deferred tax liability on our earnings deemed not indefinitely reinvested. A hypothetical tax calculation on the indefinitely reinvested earnings would require the following additional activities:

- separate analysis of a diverse chain of foreign entities;
- relying on tax rates on a future remittance that could vary significantly depending on alternative approaches available to repatriate the earnings;

- determining the nature of a yet-to-be-determined future remittance, such as whether the distribution would be a non-taxable return of capital or a distribution of taxable earnings and calculation of associated withholding taxes, which would vary significantly depending on the circumstances at the deemed time of remittance; and
- further analysis of a variety of other inputs such as the earnings, profits, U.S./foreign country tax treaty provisions and the related foreign taxes paid by our foreign subsidiaries, whose earnings are deemed permanently reinvested, over a lengthy history of operations.

Because of the administrative burden required to perform these additional activities, it is impractical to calculate a hypothetical tax on the foreign earnings associated with this separate and more complicated chain of companies.

Non-GAAP Measures

We make reference to “core earnings attributable to Devon” and “core earnings per share attributable to Devon” in “Overview of 2016 Results” in this Item 7. that are not required by or presented in accordance with GAAP. These non-GAAP measures should not be considered as alternatives to GAAP measures. Core earnings attributable to Devon, as well as the per share amount, represent net earnings excluding certain noncash or non-recurring items that are typically excluded by securities analysts in their published estimates of our financial results. Our non-GAAP measures are typically used as a quarterly performance measure. Items may appear to be recurring when comparing on an annual basis. In the table below, restructuring and transaction costs were incurred in each of the three year periods; however, these costs relate to different restructuring programs. Amounts excluded for 2016 relate to derivatives and financial instrument fair value changes, noncash asset impairments (including an impairment of goodwill), deferred tax asset valuation allowance, gains and losses on asset sales, costs associated with early retirement of debt and restructuring and transaction costs associated with the 2016 workforce reduction.

Amounts excluded for 2015 relate to derivatives and financial instrument fair value changes, asset impairments (including an impairment of goodwill), deferred tax asset valuation allowance, restructuring and transaction costs and repatriation of funds to the U.S.

Amounts excluded for 2014 relate to derivatives and financial instrument fair value changes, asset impairments (including an impairment of goodwill), gains and losses on asset sales, costs associated with early retirement of debt, restructuring and transaction costs associated with our 2014 divestiture program, repatriation of proceeds to the U.S. and deferred income tax on the formation of the General Partner. For more information on our restructuring programs, see Note 6 in “Item 8. Financial Statements and Supplementary Data” of this report.

We believe these non-GAAP measures facilitate comparisons of our performance to earnings estimates published by securities analysts, which typically make similar adjustments in their estimates of our financial results. We also believe these non-GAAP measures can facilitate comparisons of our performance between periods and to the performance of our peers.

Below are reconciliations of our core earnings and earnings per share to their comparable GAAP measures.

	Year Ended December 31,			
	Before tax	After tax	After Noncontrolling Interests	Per Share
2016				
Loss attributable to Devon (GAAP)	$ (3,877)	$ (3,704)	$ (3,302)	$ (6.52)
Adjustments:				
Gains and losses on asset sales	(1,890)	(1,243)	(1,249)	(2.44)
Asset impairments	4,996	3,599	3,176	6.28
Deferred tax asset valuation allowance	—	851	851	1.66
Restructuring and transaction costs	267	173	170	0.33
Fair value changes in financial instruments and foreign currency	270	153	145	0.28
Early retirement of debt	269	171	171	0.33
Core earnings (loss) attributable to Devon (Non-GAAP)	$ 35	$ —	$ (38)	$ (0.08)
2015				
Loss attributable to Devon (GAAP)	$ (21,268)	$ (15,203)	$ (14,454)	$ (35.55)
Adjustments:				
Asset impairments	20,820	13,923	13,100	32.18
Deferred tax asset valuation allowance	—	967	967	2.37
Restructuring and transaction costs	78	52	52	0.13
Fair value changes in financial instruments and foreign currency	1,967	1,349	1,346	3.31
Repatriations	—	33	33	0.08
Core earnings attributable to Devon (Non-GAAP)	$ 1,597	$ 1,121	$ 1,044	$ 2.52
2014				
Earnings attributable to Devon (GAAP)	$ 4,059	$ 1,691	$ 1,607	$ 3.91
Adjustments:				
Gains and losses on asset sales	(1,072)	(625)	(625)	(1.52)
Asset impairments	1,953	1,948	1,948	4.74
Restructuring and transaction costs	46	35	35	0.08
Fair value changes in financial instruments and foreign currency	(1,828)	(1,139)	(1,132)	(2.75)
Investment in General Partner deferred income tax	—	48	48	0.12
Repatriations	—	105	105	0.26
Early retirement of debt	48	31	31	0.07
Core earnings attributable to Devon (Non-GAAP)	$ 3,206	$ 2,094	$ 2,017	$ 4.91

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to our risk of loss arising from adverse changes in oil, gas and NGL prices, interest rates and foreign currency exchange rates. The following disclosures are not meant to be precise indicators of expected future losses but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is the pricing applicable to our oil, gas and NGL production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. and Canadian gas production. Pricing for oil and gas production has been volatile and unpredictable as discussed in "Item 1A. Risk Factors" of this report. Consequently, we periodically hedge a portion of our production through various financial transactions. The key terms to our oil and gas derivative financial instruments as of December 31, 2016 are presented in Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report.

The fair values of our commodity derivatives are largely determined by estimates of the forward curves of the relevant price indices. At December 31, 2016, a 10% change in the forward curves associated with our commodity derivative instruments would have changed our net liability positions by the following amounts:

	10% Increase	10% Decrease
	(Millions)	
Gain (loss):		
Gas derivatives	$ (67)	$ 64
Oil derivatives	$ (234)	$ 220
NGL derivatives	$ (1)	$ 1
Processing and fractionation derivatives	$ (3)	$ 3

Interest Rate Risk

At December 31, 2016, we had total debt of $10.2 billion. Of this amount, $10.0 billion bears fixed interest rates averaging 5.3%, and approximately $150 million is comprised of floating rate debt with interest rates averaging 2.5%.

As of December 31, 2016, we had open interest rate swap positions that are presented in Note 3 in "Item 8. Financial Statements and Supplementary Data" of this report. The fair values of our interest rate swaps are largely determined by estimates of the forward curves of the three month LIBOR rate. A 10% change in these forward curves would not have materially impacted our balance sheet or liquidity at December 31, 2016.

Foreign Currency Risk

Our net assets, net earnings and cash flows from our Canadian subsidiaries are based on the U.S. dollar equivalent of such amounts measured in the Canadian dollar functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using an average exchange rate during the reporting period. A 10% unfavorable change in the Canadian-to-U.S. dollar exchange rate would not have materially impacted our December 31, 2016 balance sheet.

Our non-Canadian foreign subsidiaries have a U.S. dollar functional currency. However, some of our subsidiaries hold Canadian-dollar cash and engage in intercompany loans with Canadian subsidiaries that are based in Canadian dollars. The value of the Canadian-dollar cash and intercompany loans increases or decreases from the remeasurement of the cash and loans into the U.S. dollar functional currency. Based on the amount of the cash and intercompany loans as of December 31, 2016, a 10% change in the foreign currency exchange rates would not have materially impacted our balance sheet.

Item 8. ***Financial Statements and Supplementary Data***

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

All financial statement schedules are omitted as they are inapplicable or the required information has been included in the consolidated financial statements or notes thereto.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Devon Energy Corporation:

We have audited the accompanying consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 2016 and 2015, and the related consolidated comprehensive statements of earnings, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2016. We also have audited Devon Energy Corporation's 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 (COSO). Devon Energy Corporation's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report contained in "Item 9A. Controls and Procedures" of Devon Energy Corporation's Annual Report on Form 10-K. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company's internal control over financial reporting 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Devon Energy Corporation and subsidiaries as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles. Also in our opinion, Devon Energy Corporation maintained, in all material respects, effective 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 (COSO).

/s/ KPMG LLP

Oklahoma City, Oklahoma
February 15, 2017

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED COMPREHENSIVE STATEMENTS OF EARNINGS

	Year Ended December 31,		
	2016	2015	2014
	(Millions, except per share amounts)		
Oil, gas and NGL sales	$ 4,182	$ 5,382	$ 9,910
Oil, gas and NGL derivatives	(201)	503	1,989
Marketing and midstream revenues	6,323	7,260	7,667
Asset dispositions and other	1,893	—	1,072
Total revenues and other	12,197	13,145	20,638
Lease operating expenses	1,582	2,104	2,332
Marketing and midstream operating expenses	5,492	6,420	6,815
General and administrative expenses	645	855	847
Production and property taxes	275	388	535
Depreciation, depletion and amortization	1,792	3,129	3,319
Asset impairments	4,975	20,820	1,953
Restructuring and transaction costs	267	78	46
Other operating items	64	78	93
Total operating expenses	15,092	33,872	15,940
Operating income (loss)	(2,895)	(20,727)	4,698
Net financing costs	904	517	526
Other nonoperating items	78	24	113
Earnings (loss) before income taxes	(3,877)	(21,268)	4,059
Income tax expense (benefit)	(173)	(6,065)	2,368
Net earnings (loss)	(3,704)	(15,203)	1,691
Net earnings (loss) attributable to noncontrolling interests	(402)	(749)	84
Net earnings (loss) attributable to Devon	$ (3,302)	$ (14,454)	$ 1,607
Net earnings (loss) per share attributable to Devon:			
Basic	$ (6.52)	$ (35.55)	$ 3.93
Diluted	$ (6.52)	$ (35.55)	$ 3.91
Comprehensive earnings (loss):			
Net earnings (loss)	$ (3,704)	$ (15,203)	$ 1,691
Other comprehensive earnings (loss), net of tax:			
Foreign currency translation	32	(559)	(465)
Pension and postretirement plans	22	10	(24)
Other comprehensive earnings (loss), net of tax	54	(549)	(489)
Comprehensive earnings (loss)	(3,650)	(15,752)	1,202
Comprehensive earnings (loss) attributable to noncontrolling interests	(402)	(749)	84
Comprehensive earnings (loss) attributable to Devon	$ (3,248)	$ (15,003)	$ 1,118

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
Cash flows from operating activities:			
Net earnings (loss)	$ (3,704)	$ (15,203)	$ 1,691
Adjustments to reconcile net earnings (loss) to net cash from operating activities:			
Depreciation, depletion and amortization	1,792	3,129	3,319
Asset impairments	4,975	20,820	1,953
Gains and losses on asset sales	(1,887)	—	(1,072)
Deferred income tax expense (benefit)	(273)	(5,828)	1,891
Derivatives and other financial instruments	386	(738)	(2,070)
Cash settlements on derivatives and financial instruments	(142)	2,688	104
Asset retirement obligation accretion	75	75	89
Amortization of stock-based compensation	194	181	163
Other	303	281	245
Net change in working capital	(8)	(311)	50
Change in long-term other assets	36	285	(421)
Change in long-term other liabilities	(1)	(6)	79
Net cash from operating activities	1,746	5,373	6,021
Cash flows from investing activities:			
Capital expenditures	(2,330)	(5,308)	(6,988)
Acquisitions of property, equipment and businesses	(1,641)	(1,107)	(6,462)
Divestitures of property and equipment	3,118	107	5,120
Redemptions of long-term investments	—	—	57
Other	(19)	(16)	89
Net cash from investing activities	(872)	(6,324)	(8,184)
Cash flows from financing activities:			
Borrowings of long-term debt, net of issuance costs	2,145	4,772	5,340
Repayments of long-term debt	(4,409)	(2,634)	(7,178)
Net short-term debt repayments	(626)	(307)	(385)
Early retirement of debt	(265)	—	(51)
Issuance of common stock	1,469	—	—
Sale of subsidiary units	—	654	—
Issuance of subsidiary units	892	25	410
Dividends paid on common stock	(221)	(396)	(386)
Contributions from noncontrolling interests	168	16	6
Distributions to noncontrolling interests	(304)	(254)	(235)
Other	(13)	(18)	85
Net cash from financing activities	(1,164)	1,858	(2,394)
Effect of exchange rate changes on cash	(61)	(77)	(29)
Net change in cash and cash equivalents	(351)	830	(4,586)
Cash and cash equivalents at beginning of period	2,310	1,480	6,066
Cash and cash equivalents at end of period	$ 1,959	$ 2,310	$ 1,480

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

		December 31, 2016		December 31, 2015
	(Millions, except share data)			
ASSETS				
Current assets:				
Cash and cash equivalents	$	1,959	$	2,310
Accounts receivable		1,356		1,105
Assets held for sale		193		—
Other current assets		264		606
Total current assets		3,772		4,021
Property and equipment, at cost:				
Oil and gas, based on full cost accounting:				
Subject to amortization		75,648		78,190
Not subject to amortization		3,437		2,584
Total oil and gas		79,085		80,774
Midstream and other		10,455		10,380
Total property and equipment, at cost		89,540		91,154
Less accumulated depreciation, depletion and amortization		(73,350)		(72,086)
Property and equipment, net		16,190		19,068
Goodwill		3,964		5,032
Other long-term assets		1,987		1,330
Total assets	$	25,913	$	29,451
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$	642	$	906
Revenues and royalties payable		908		763
Short-term debt		—		976
Other current liabilities		1,066		650
Total current liabilities		2,616		3,295
Long-term debt		10,154		12,056
Asset retirement obligations		1,226		1,370
Other long-term liabilities		894		853
Deferred income taxes		648		888
Stockholders' equity:				
Common stock, $0.10 par value. Authorized 1.0 billion shares; issued 523 million and 418 million shares in 2016 and 2015, respectively		52		42
Additional paid-in capital		7,237		4,996
Retained earnings (accumulated deficit)		(1,646)		1,781
Accumulated other comprehensive earnings		284		230
Total stockholders' equity attributable to Devon		5,927		7,049
Noncontrolling interests		4,448		3,940
Total stockholders' equity		10,375		10,989
Total liabilities and stockholders' equity	$	25,913	$	29,451

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Earnings	Treasury Stock	Noncontrolling Interests	Total Stockholders' Equity
	(Millions)							
Balance as of December 31, 2013	406	$ 41	$ 3,780	$ 15,410	$ 1,268	$ —	$ —	$ 20,499
Net earnings	—	—	—	1,607	—	—	84	1,691
Other comprehensive loss, net of tax	—	—	—	—	(489)	—	—	(489)
Stock option exercises	1	—	93	—	—	—	—	93
Restricted stock grants, net of cancellations	2	—	—	—	—	—	—	—
Common stock repurchased	—	—	—	—	—	(27)	—	(27)
Common stock retired	—	—	(27)	—	—	27	—	—
Common stock dividends	—	—	—	(386)	—	—	—	(386)
Share-based compensation	—	—	151	—	—	—	—	151
Share-based compensation tax expense	—	—	(3)	—	—	—	—	(3)
Acquisition of noncontrolling interests	—	—	—	—	—	—	4,670	4,670
Subsidiary equity transactions	—	—	93	—	—	—	277	370
Distributions to noncontrolling interests	—	—	—	—	—	—	(235)	(235)
Other	—	—	1	—	—	—	6	7
Balance as of December 31, 2014	409	$ 41	$ 4,088	$ 16,631	$ 779	$ —	$ 4,802	$ 26,341
Net loss	—	—	—	(14,454)	—	—	(749)	(15,203)
Other comprehensive loss, net of tax	—	—	—	—	(549)	—	—	(549)
Stock option exercises	—	—	4	—	—	—	—	4
Restricted stock grants, net of cancellations	2	—	—	—	—	—	—	—
Common stock repurchased	—	—	—	—	—	(35)	—	(35)
Common stock retired	—	—	(35)	—	—	35	—	—
Common stock dividends	—	—	—	(396)	—	—	—	(396)
Common stock issued	7	1	198	—	—	—	—	199
Share-based compensation	—	—	165	—	—	—	—	165
Share-based compensation tax expense	—	—	(9)	—	—	—	—	(9)
Subsidiary equity transactions	—	—	585	—	—	—	141	726
Distributions to noncontrolling interests	—	—	—	—	—	—	(254)	(254)
Balance as of December 31, 2015	418	$ 42	$ 4,996	$ 1,781	$ 230	$ —	$ 3,940	$ 10,989
Net loss	—	—	—	(3,302)	—	—	(402)	(3,704)
Other comprehensive earnings, net of tax	—	—	—	—	54	—	—	54
Restricted stock grants, net of cancellations	2	—	—	—	—	—	—	—
Common stock repurchased	—	—	—	—	—	(28)	—	(28)
Common stock retired	—	—	(28)	—	—	28	—	—
Common stock dividends	—	—	(96)	(125)	—	—	—	(221)
Common stock issued	103	10	2,117	—	—	—	—	2,127
Share-based compensation	—	—	168	—	—	—	—	168
Subsidiary equity transactions	—	—	80	—	—	—	1,214	1,294
Distributions to noncontrolling interests	—	—	—	—	—	—	(304)	(304)
Balance as of December 31, 2016	523	$ 52	$ 7,237	$ (1,646)	$ 284	$ —	$ 4,448	$ 10,375

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Devon is a leading independent energy company engaged primarily in the exploration, development and production of oil, natural gas and NGLs. Devon's operations are concentrated in various North American onshore areas in the U.S. and Canada. Devon also owns natural gas pipelines, plants and treatment facilities through its ownership in EnLink and the General Partner.

Accounting policies used by Devon and its subsidiaries conform to accounting principles generally accepted in the U.S. and reflect industry practices. The more significant of such policies are discussed below.

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Devon and entities in which it holds a controlling interest. All intercompany transactions have been eliminated. Undivided interests in oil and natural gas exploration and production joint ventures are consolidated on a proportionate basis. Investments in non-controlled entities, over which Devon has the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method. In applying the equity method of accounting, the investments are initially recognized at cost and subsequently adjusted for Devon's proportionate share of earnings, losses and distributions. Investments accounted for using the equity method and cost method are reported as a component of other long-term assets.

As discussed more fully in Note 2, Devon completed a business combination in 2014 whereby Devon controls both EnLink and the General Partner. Devon controls both the General Partner's and EnLink's operations; therefore, the General Partner's and EnLink's accounts are included in Devon's accompanying consolidated financial statements subsequent to the completion of the transaction. The portions of the General Partner's and EnLink's net earnings and stockholders' equity not attributable to Devon's controlling interest are shown separately as noncontrolling interests in the accompanying consolidated comprehensive statements of earnings and consolidated balance sheets.

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known. Significant items subject to such estimates and assumptions include the following:

- proved reserves and related present value of future net revenues;
- the carrying value of oil and gas properties, midstream assets and product and equipment inventories;
- derivative financial instruments;
- the fair value of reporting units and related assessment of goodwill for impairment;
- the fair value of intangible assets other than goodwill;
- income taxes;
- asset retirement obligations;
- obligations related to employee pension and postretirement benefits;

- legal and environmental risks and exposures; and
- general credit risk associated with receivables and other assets.

Revenue Recognition

Oil, gas and NGL sales are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectability of the revenue is probable. Delivery occurs and title typically is transferred when production has been delivered to a pipeline, railcar or truck. Cash received relating to future production is deferred and recognized when all revenue recognition criteria are met. Taxes assessed by governmental authorities on oil, gas and NGL sales are presented separately from such revenues in the accompanying consolidated comprehensive statements of earnings.

Marketing and midstream revenues are recorded at the time products are sold or services are provided to third parties at a fixed or determinable price, delivery or performance has occurred, title has transferred and collectability of the revenue is probable. Revenues and expenses attributable to oil, gas and NGL purchases, transportation and processing contracts are reported on a gross basis when Devon takes title to the products and has risks and rewards of ownership.

During 2016, 2015 and 2014, no purchaser accounted for more than 10% of Devon's consolidated sales revenue.

Derivative Financial Instruments

Devon is exposed to certain risks relating to its ongoing business operations, including risks related to commodity prices, interest rates and Canadian to U.S. dollar exchange rates. As discussed more fully below, Devon uses derivative instruments primarily to manage commodity price risk, interest rate risk and foreign exchange risk. Devon does not intend to issue or hold derivative financial instruments for speculative trading purposes.

Devon enters into derivative financial instruments with respect to a portion of its oil, gas and NGL production to hedge future prices received. Additionally, Devon and EnLink periodically enter into derivative financial instruments with respect to a portion of their oil, gas and NGL marketing activities. These instruments are used to manage the inherent uncertainty of future revenues resulting from commodity price volatility. Devon's derivative financial instruments typically include financial price swaps, basis swaps, costless price collars and call options. Under the terms of the price swaps, Devon receives a fixed price for its production and pays a variable market price to the contract counterparty. For the basis swaps, Devon receives a fixed differential between two regional index prices and pays a variable differential on the same two index prices to the contract counterparty. The price collars set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon will cash-settle the difference with the counterparty to the collars. The call options give counterparties the right to purchase production at a predetermined price.

Devon periodically enters into interest rate swaps to manage its exposure to interest rate volatility and foreign exchange forward contracts to manage its exposure to fluctuations in the U.S. and Canadian dollar exchange rates. As of December 31, 2016, Devon did not have any open foreign exchange contracts.

All derivative financial instruments are recognized at their current fair value as either assets or liabilities in the balance sheet. Changes in the fair value of these derivative financial instruments are recorded in earnings unless specific hedge accounting criteria are met. For derivative financial instruments held during the three-year period ended December 31, 2016, Devon chose not to meet the necessary criteria to qualify its derivative financial instruments for hedge accounting treatment. Cash settlements with counterparties on Devon's derivative financial instruments are also recorded in earnings. Cash settlements that Devon is entitled to are accrued for in other current assets in the accompanying consolidated balance sheets. As of December 31, 2015, Devon accrued $236 million that it received in January 2016 related to cash settlements.

By using derivative financial instruments to hedge exposures to changes in commodity prices, interest rates and foreign currency rates, Devon is exposed to credit risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are placed with a number of counterparties whom Devon believes are acceptable credit risks. It is Devon's policy to enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers. Additionally, Devon's derivative contracts generally require cash collateral to be posted if either its or the counterparty's credit rating falls below certain credit rating levels. As of December 31, 2016, Devon held no collateral from counterparties. As of December 31, 2015, Devon held $75 million of cash collateral, which represented the estimated fair value of certain derivative positions in excess of Devon's credit guidelines. The collateral is reported in other current liabilities in the accompanying consolidated balance sheets. As a result of ratings downgrades for Devon during 2016, we were required to post $17 million of cash collateral under certain of our derivative contracts. The collateral is reported in other current assets in the accompanying December 31, 2016 consolidated balance sheet. In January 2017, this collateral was deemed to be no longer required and was returned to Devon. As of the date of this report, Devon has no cash collateral held by its counterparties.

General and Administrative Expenses

G&A is reported net of amounts reimbursed by working interest owners of the oil and gas properties operated by Devon and net of amounts capitalized pursuant to the full cost method of accounting.

Share-Based Compensation

Independent of EnLink, Devon grants share-based awards to members of its Board of Directors and select employees. EnLink and the General Partner also grant share-based awards to members of its Board of Directors and select employees. All such awards are measured at fair value on the date of grant and are generally recognized as a component of G&A in the accompanying consolidated comprehensive statements of earnings over the applicable requisite service periods. As a result of Devon's restructuring activity discussed in Note 6, certain share-based awards were accelerated and recognized as a component of restructuring costs in the accompanying consolidated comprehensive statements of earnings.

Generally, Devon uses new shares from approved incentive programs to grant share-based awards and to issue shares upon stock option exercises. Shares repurchased under approved programs are available to be issued as part of Devon's share-based awards. However, Devon has historically canceled these shares upon repurchase.

Income Taxes

Devon is subject to current income taxes assessed by the federal and various state jurisdictions in the U.S. and by other foreign jurisdictions. In addition, Devon accounts for deferred income taxes related to these jurisdictions using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of existing tax net operating loss carryforwards and other types of carryforwards. If the future utilization of some portion of the deferred tax assets is determined to be unlikely, a valuation allowance is provided to reduce the recorded tax benefits from such assets. Devon periodically weighs the positive and negative evidence to determine if it is more likely than not that some or all of the deferred tax assets will be realized. Forming a conclusion that a valuation allowance is not required is difficult when there is negative evidence, such as cumulative losses in recent years. See Note 7 for further discussion.

Devon does not recognize U.S. deferred income taxes on the unremitted earnings of its foreign subsidiaries that are deemed to be indefinitely reinvested. When such earnings are no longer deemed indefinitely reinvested, Devon recognizes the appropriate deferred, or even current, income tax liabilities.

Devon recognizes the financial statement effects of tax positions when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a taxing authority. Recognized tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not of being realized upon ultimate settlement with a taxing authority. Liabilities for unrecognized tax benefits related to such tax positions are included in other long-term liabilities unless the tax position is expected to be settled within the upcoming year, in which case the liabilities are included in other current liabilities. Interest and penalties related to unrecognized tax benefits are included in current income tax expense.

Devon estimates its annual effective income tax rate in recording its provision for income taxes in the various jurisdictions in which it operates. Statutory tax rate changes and other significant or unusual items are recognized as discrete items in the period in which they occur.

Net Earnings (Loss) Per Share Attributable to Devon

Devon's basic earnings per share amounts have been computed based on the average number of shares of common stock outstanding for the period. Basic earnings per share includes the effect of participating securities, which primarily consist of Devon's outstanding restricted stock awards, as well as performance-based restricted stock awards that have met the requisite performance targets. Diluted earnings per share is calculated using the treasury stock method to reflect the assumed issuance of common shares for all potentially dilutive securities. Such securities primarily consist of outstanding stock options.

Cash and Cash Equivalents

Devon considers all highly liquid investments with original contractual maturities of three months or less to be cash equivalents.

Accounts Receivable

Devon's accounts receivable balance primarily consists of oil and gas sales receivables, marketing and midstream revenue receivables and joint interest receivables for which Devon does not require collateral security. Devon has established an allowance for bad debts equal to the estimable portions of accounts receivable for which failure to collect is considered probable. When a portion of the receivable is deemed uncollectible, the write-off is made against the allowance.

Property and Equipment

Devon follows the full cost method of accounting for its oil and gas properties. Accordingly, all costs incidental to the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, dry holes and leasehold equipment, are capitalized. Internal costs incurred that are directly identified with acquisition, exploration and development activities undertaken by Devon for its own account, and that are not related to production, general corporate overhead or similar activities, are also capitalized. Interest costs incurred and attributable to unproved oil and gas properties under current evaluation and major development projects of oil and gas properties are also capitalized. All costs related to production activities, including workover costs incurred solely to maintain or increase levels of production from an existing completion interval, are charged to expense as incurred.

Capitalized costs are depleted by an equivalent unit-of-production method, converting gas to oil at the ratio of six Mcf of gas to one Bbl of oil. Depletion is calculated using the capitalized costs, including estimated asset retirement costs, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values.

Costs associated with unproved properties are excluded from the depletion calculation until it is determined whether or not proved reserves can be assigned to such properties. Devon assesses its unproved properties for impairment quarterly. Significant unproved properties are assessed individually. Costs of insignificant unproved properties are transferred into the depletion calculation over their respective holding periods generally ranging from three to four years.

Sales or dispositions of oil and gas properties are generally accounted for as adjustments to capitalized costs with no gain or loss recognized. However, if a disposition or series of dispositions occurring in a quarterly reporting period significantly alters the relationship between capitalized costs and proved reserves in a particular country, a gain or loss is recognized. As discussed more fully in Note 2, the 2014 and 2016 divestitures of certain Canadian and U.S. non-core upstream assets significantly altered such relationship, and Devon recognized gains on these transactions. These gains are classified as asset dispositions and other in the accompanying consolidated statements of earnings. Furthermore, upon recognizing the gain on the 2016 divestitures and to be more consistent with industry practice, Devon began presenting gains on asset sales in the total revenues and other section of the accompanying consolidated statements of earnings, and has reclassified the 2014 gain on asset sales of $1.1 billion from operating expenses to total revenues and other to reflect consistent financial statement presentation.

Under the full cost method of accounting, capitalized costs of oil and gas properties, net of accumulated DD&A and deferred income taxes, may not exceed the full cost "ceiling" at the end of each quarter. The ceiling is calculated separately for each country and is based on the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10% per annum, net of related tax effects. The estimated future net revenues exclude future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties.

Estimated future net cash flows are calculated using end-of-period costs and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months. Prices are held constant indefinitely and are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including derivative contracts in place that qualify for hedge accounting treatment. None of Devon's derivative contracts held during the three-year period ended December 31, 2016 qualified for hedge accounting treatment.

Any excess of the net book value, less related deferred taxes, over the ceiling is written off as an expense. An expense recorded in one period may not be reversed in a subsequent period even though higher commodity prices may have increased the ceiling applicable to the subsequent period.

Costs for midstream assets that are in use are depreciated over the assets' estimated useful lives, using either the unit-of-production or straight-line method. Depreciation and amortization of other property and equipment, including corporate and leasehold improvements, are provided using the straight-line method based on estimated useful lives ranging from three to 60 years. Interest costs incurred and attributable to major midstream and corporate construction projects are also capitalized.

Devon recognizes liabilities for retirement obligations associated with tangible long-lived assets, such as producing well sites and midstream pipelines and processing plants when there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The initial measurement of an asset retirement obligation is recorded as a liability at its fair value, with an offsetting asset retirement cost recorded as an increase to the associated property and equipment on the consolidated balance sheet. When the assumptions used to estimate a recorded asset retirement obligation change, a revision is recorded to both the asset retirement obligation and the asset retirement cost. Devon's asset retirement obligations include estimated environmental remediation costs which arise from normal operations and are associated with the retirement of such long-lived assets. The asset retirement cost is depreciated using a systematic and rational method similar to that used for the associated property and equipment.

Goodwill

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired and is tested for impairment annually, or more frequently if events or changes in circumstances dictate that the carrying value of goodwill may not be recoverable. Such test includes an assessment of qualitative and quantitative factors. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. The fair value of each reporting unit is estimated and compared to the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense. Because quoted market prices are not available for Devon's reporting units, the fair values of the reporting units are estimated based upon several valuation analyses, including comparable companies, comparable transactions and premiums paid.

Devon and EnLink performed annual impairment tests of goodwill in the fourth quarters of 2016, 2015 and 2014. No impairment write-down was required as a result of the annual tests in 2016; however, sustained weakness in the overall energy sector driven by low commodity prices, together with a decline in the EnLink unit price, caused a change in circumstances warranting an interim impairment test and write-down for certain of EnLink's reporting units in the first quarter of 2016. Write-downs were also required in 2015 for certain EnLink reporting units and in 2014 for Devon's Canadian reporting unit based on interim and annual impairment tests. See Note 12 for further discussion.

Intangible Assets

Unamortized capitalized intangible assets, consisting of EnLink customer relationships, are presented in other long-term assets in the accompanying consolidated balance sheets. These assets are amortized on a straight-line basis over the expected periods of benefits, which range from 10-20 years. During 2016 and 2015, EnLink's customer relationships were also evaluated for impairment, and in 2015, a portion of these intangible assets was considered impaired. See Note 12 for further discussion.

Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Liabilities for environmental remediation or restoration claims resulting from improper operation of assets are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Expenditures related to such environmental matters are expensed or capitalized in accordance with Devon's accounting policy for property and equipment.

Fair Value Measurements

Certain of Devon's assets and liabilities are measured at fair value at each reporting date. Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants. This price is commonly referred to as the "exit price." Fair value measurements are classified according to a hierarchy that prioritizes the inputs underlying the valuation techniques. This hierarchy consists of three broad levels:

- Level 1 – Inputs consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. When available, Devon measures fair value using Level 1 inputs because they generally provide the most reliable evidence of fair value.
- Level 2 – Inputs consist of quoted prices that are generally observable for the asset or liability. Common examples of Level 2 inputs include quoted prices for similar assets and liabilities in active markets or quoted prices for identical assets and liabilities in markets not considered to be active.
- Level 3 – Inputs are not observable from objective sources and have the lowest priority. The most common Level 3 fair value measurement is an internally developed cash flow model.

Foreign Currency Translation Adjustments

The U.S. dollar is the functional currency for Devon's consolidated operations except its Canadian subsidiaries, which use the Canadian dollar as the functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using an average exchange rate during the reporting period. Translation adjustments have no effect on net income and are included in accumulated other comprehensive earnings in stockholders' equity.

Noncontrolling Interests

Noncontrolling interests represent third-party ownership in the net assets of Devon's consolidated subsidiaries and are presented as a component of equity. Changes in Devon's ownership interests in subsidiaries that do not result in deconsolidation are recognized in equity.

Recently Adopted Accounting Standards

In January 2016, Devon adopted ASU 2015-03, *Interest – Imputation of Interest (Topic 835): Simplifying the Presentation of Debt Issuance Costs.* This ASU requires debt issuance costs related to a recognized debt liability to be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability rather than as an asset. As a result of the adoption, Devon reclassified unamortized debt issuance costs of $81 million as of December 31, 2015 from other long-term assets to a reduction of long-term debt on the consolidated balance sheets.

The FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments.* Its objective is to clarify guidance and eliminate diversity in practice of classification on certain cash receipts and payments in the statement of cash flows. Devon early adopted this ASU as of September

30, 2016 using a retrospective transition method. As a result of the adoption, Devon has classified $265 million of debt retirement payments as cash flows from financing activities in the accompanying 2016 consolidated statement of cash flows and has reclassified $40 million of debt retirement payments previously classified as cash flows from operating activities to cash flows from financing activities in the accompanying 2014 consolidated statement of cash flows.

The FASB issued ASU 2014-15*, Presentation of Financial Statements – Going Concern (Subtopic 205-40): Disclosures of Uncertainties about an Entity's Ability to Continue as a Going Concern*. Its objective is to provide guidance about management's responsibility to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern. Certain disclosures are required should substantial doubt exist. This evaluation is performed each annual and interim reporting period to assess conditions or events within one year after the date that the financial statements are issued. This ASU was effective for Devon beginning December 31, 2016; however, no additional disclosures as contemplated by this ASU were warranted.

Recently Issued Accounting Standards

The FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. This ASU will supersede the revenue recognition requirements in Topic 605, *Revenue Recognition* and industry-specific guidance in Subtopic 932-605, *Extractive Activities – Oil and Gas – Revenue Recognition.* This ASU provides guidance concerning the recognition and measurement of revenue from contracts with customers. Its objective is to increase the usefulness of information in the financial statements regarding the nature, timing and uncertainty of revenues. The effective date for ASU 2014-09 was delayed through the issuance of ASU 2015-14, *Revenue from Contracts with Customers – Deferral of the Effective Date,* to annual and interim periods beginning in 2018, with early adoption permitted in 2017. The ASU is required to be adopted using either the retrospective transition method, which requires restating previously reported results or the cumulative effect (modified retrospective) transition method, which utilizes a cumulative-effect adjustment to retained earnings in the period of adoption to account for prior period effects rather than restating previously reported results. Devon intends to use the cumulative effect transition method. Based on current evaluations to-date, Devon does not anticipate this ASU will have a material impact on its balance sheet or related consolidated statement of earnings, stockholders' equity or cash flows. Devon is continuing to evaluate the disclosure requirements of this ASU and has begun transitioning to the implementation phase of the adoption. Devon does not plan on early adopting this ASU.

The FASB issued ASU 2016-02, *Leases (Topic 842)*. This ASU will supersede the lease requirements in Topic 840, *Leases*. Its objective is to increase transparency and comparability among organizations. This ASU provides guidance requiring lessees to recognize most leases on their balance sheet. Lessor accounting does not significantly change, except for some changes made to align with new revenue recognition requirements. This ASU is effective for Devon beginning January 1, 2019 and will be applied using a modified retrospective transition method, which requires applying the new guidance to leases that exist or are entered into after the beginning of the earliest period in the financial statements. Early adoption is permitted. Devon is continuing to evaluate the impact this ASU will have on its consolidated financial statements and related disclosures and does not plan on early adopting.

The FASB issued ASU 2016-09, *Compensation – Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*. Its objective is to simplify several aspects of the accounting for share-based payments, and associated income taxes, statutory withholding and forfeitures. Classification of these aspects on the statement of cash flows is also addressed. Devon adopted this ASU as of January 1, 2017. For recording periods following adoption, Devon will make certain income tax presentation changes, most notably prospectively presenting excess tax benefits as income tax expense in the consolidated comprehensive statements of earnings and as operating cash flows in the consolidated statements of cash flows. While Devon does not expect that these changes will materially impact its consolidated financial statements and related disclosures, the adoption of this ASU could result in increased volatility in income tax expense and net earnings in Devon's financial statements.

The FASB issued ASU No. 2016-13, *Credit Losses, Measurement of Credit Losses on Financial Instruments*. This ASU changes how entities will measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The standard will replace today's incurred loss approach with an expected loss model for instruments measured at amortized cost. Entities will apply the standard's provisions as a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. This ASU is effective for Devon beginning January 1, 2020, with early adoption permitted. Devon is evaluating the impact this ASU will have on its consolidated financial statements and related disclosures.

2. Acquisitions and Divestitures

Devon Acquisitions

On January 7, 2016, Devon acquired approximately 80,000 net acres (unaudited) and assets in the STACK play for approximately $1.5 billion. Devon funded the acquisition with $849 million of cash and $659 million of equity. The allocation of the purchase price at December 31, 2016 was approximately $1.3 billion to unproved properties and approximately $200 million to proved properties.

On December 17, 2015, Devon acquired approximately 253,000 net acres (unaudited) and assets in the Powder River Basin for approximately $499 million. Devon funded the acquisition with $300 million of cash and $199 million of equity. The allocation of the purchase price was $393 million to unproved properties and $106 million to proved properties and gathering systems.

On February 28, 2014, Devon acquired approximately 82,000 net acres (unaudited) and assets located in DeWitt and Lavaca counties in south Texas from GeoSouthern for approximately $6.0 billion. Devon funded the acquisition with cash on hand and debt financing. The allocation of the purchase price was approximately $5.0 billion to proved properties and approximately $1.0 billion to unproved properties.

Devon Asset Divestitures

During 2016, Devon divested certain non-core upstream assets in the U.S. and its 50% interest in the Access Pipeline in Canada. Proceeds from the transactions have been utilized primarily for debt repayment and to support future capital investment in Devon's core resource plays.

Upstream Assets

In the second quarter of 2016, Devon divested its non-core Mississippian assets for approximately $200 million. Estimated proved reserves associated with these assets were approximately 11 MMBoe, or less than 1% of total U.S. proved reserves.

During the third quarter of 2016, in several separate transactions with different purchasers, Devon divested non-core upstream assets located in east Texas, the Anadarko Basin and the Midland Basin for approximately $1.7 billion. Estimated proved reserves associated with these assets were approximately 146 MMBoe, or approximately 9% of total U.S. proved reserves.

Absent gain recognition, the divestiture transactions that closed in the third quarter of 2016 would have significantly altered the costs and reserves relationship of Devon's U.S cost center. Therefore, Devon recognized a

$1.4 billion gain in the third quarter of 2016 associated with these divestitures. A summary of the gain computation follows.

	Three Months Ended September 30, 2016 (Millions)
Proceeds received, net of purchase price adjustments and selling costs	$ 1,653
Asset retirement obligation assumed by purchasers	250
Total consideration received	1,903
Allocated oil and gas property basis sold	355
Allocated goodwill	197
Total assets sold	552
Gains on asset sales	$ 1,351

Access Pipeline

In October 2016, Devon divested Access Pipeline for $1.1 billion ($1.4 billion Canadian dollars) and recognized a gain of approximately $540 million on the transaction. In conjunction with the divestiture, Devon entered into a transportation agreement whereby Devon's Canadian thermal-oil acreage is dedicated to Access Pipeline for an initial term of 25 years. Devon will be charged a market-based toll on its thermal-oil production over this term. Devon is committed to use less than 90% of the potential pipeline capacity. In addition, Devon is entitled to an incremental payment of approximately $150 million Canadian dollars following sanctioning and committing to the requisite volume increase in respect of a new thermal-oil project on Devon's Pike lease in Alberta, with such incremental payment being received prior to tolls being payable on such volumes.

Prior Year Divestitures

During 2014, Devon divested certain upstream properties located throughout Canada and the U.S. as part of its asset portfolio transformation for approximately $5 billion. A gain of $1.1 billion was recognized with the sale of the Canadian conventional assets. This gain is included as a separate item in the accompanying consolidated comprehensive statements of earnings. Devon repatriated the Canadian asset proceeds to the U.S. Between collecting the divestiture proceeds and repatriating the funds to the U.S., Devon recognized an $84 million foreign currency exchange loss and a $29 million foreign exchange currency derivative loss. These losses are included in other nonoperating items in the accompanying consolidated comprehensive statements of earnings. The proceeds were used to repay debt.

EnLink Acquisitions

On January 7, 2016, EnLink acquired Anadarko Basin gathering and processing midstream assets, along with dedicated acreage service rights and service contracts, for approximately $1.5 billion, subject to certain adjustments. EnLink funded the acquisition with approximately $215 million of General Partner common units and approximately $800 million of cash, primarily funded with the issuance of EnLink preferred units. The remaining $500 million of the purchase price is to be paid within one year with the option to defer $250 million of the final payment 24 months from the close date. The first $250 million of undiscounted future installment payment is reported in other current liabilities in the accompanying consolidated balance sheets with the remaining $250 million payment reported in other long-term liabilities. The accretion of the discount is reported within net financing costs in the accompanying consolidated comprehensive statement of earnings. The first installment payment of $250 million was paid in January 2017 and was funded using divestiture proceeds, proceeds from equity issuances and borrowings under EnLink's credit facility. The allocation of the purchase price at December 31, 2016 was $1.0 billion to intangible assets and approximately $400 million to property and equipment.

On August 1, 2016, EnLink formed a joint venture to operate and expand its midstream assets in the Delaware Basin. The joint venture is initially owned 50.1% by EnLink and 49.9% by the joint venture partner. As of December 31, 2016, EnLink contributed approximately $251 million of existing non-monetary assets and cash to the joint venture and had committed an additional $285 million in capital to fund potential future development projects and potential acquisitions. The joint venture partner committed an aggregate of approximately $400 million of capital, including cash contributions of approximately $144 million, and granted EnLink call rights beginning in 2021 to acquire increasing portions of the joint venture partner's interest.

On November 9, 2016, EnLink entered into a gathering and compression joint venture with a commitment of approximately $40 million to expand its midstream assets in the STACK. The joint venture is initially owned 30% by EnLink and 70% by the joint venture partner. As of December 31, 2016, EnLink contributed approximately $29 million in cash for new infrastructure build. After the initial capital commitment, EnLink and the joint venture partner will be responsible for their proportionate share of capital expenses.

The following table presents a summary of EnLink's acquisition activity for 2015.

		Purchase Price (Millions)		Allocation (Millions)			
Date	Acquiree	Cash	EnLink Units	PP&E	Goodwill	Intangibles	Other
January 2015	LPC	$ 108	—	$ 30	$ 30	$ 43	$ 5
March 2015	Coronado	$ 240	$ 360	$ 302	$ 18	$ 281	$ (1)
October 2015	Matador	$ 141	—	$ 36	$ 11	$ 99	$ (5)

EnLink Asset Divestitures and Dropdowns

In December 2016, EnLink entered into definitive agreements to divest approximately $278 million of certain non-core midstream assets. Certain of these transactions are expected to close during the first quarter of 2017. As of December 31, 2016, these assets were classified as held for sale.

In February 2015, EnLink acquired a 25% equity interest in EMH from the General Partner in exchange for units valued at approximately $925 million. In May 2015, EnLink acquired the remaining 25% equity interest in EMH from the General Partner in exchange for units valued at approximately $900 million.

In April 2015, EnLink acquired VEX from Devon for approximately $176 million in cash and equity. EnLink also assumed approximately $35 million in certain future construction costs to expand the system to full capacity. Because Devon controls EnLink and the General Partner, the acquisition of VEX by EnLink from Devon was accounted for as a transfer of net assets between entities under common control.

Formation of EnLink and the General Partner

On March 7, 2014, Devon and Crosstex completed a transaction to combine substantially all of Devon's U.S. midstream assets with Crosstex's assets to form a midstream business that consists of the General Partner and EnLink, which are both publicly traded.

In exchange for a controlling interest in both EnLink and the General Partner, Devon contributed its equity interest in a newly formed Devon subsidiary, EMH, and $100 million in cash. EMH owned midstream assets in the Barnett Shale in north Texas and the Cana- and Arkoma-Woodford Shales in Oklahoma, as well as an economic interest in Gulf Coast Fractionators in Mont Belvieu, Texas.

This business combination was accounted for using the acquisition method of accounting. Under the acquisition method of accounting, EMH was the accounting acquirer because its parent company, Devon, obtained control of EnLink and the General Partner as a result of the business combination. Consequently, EMH's assets and liabilities retained their carrying values. Additionally, the Crosstex assets acquired and liabilities assumed by the General Partner and EnLink in the business combination, as well as the General Partner's noncontrolling interest in EnLink, were recorded at their fair values which were measured as of the acquisition date, March 7, 2014. The excess of the purchase price over the estimated fair values of Crosstex's net assets acquired was recorded as goodwill.

The following table summarizes the purchase price (millions, except unit price).

Crosstex Energy, Inc. outstanding common shares:		
Held by public shareholders		48.0
Restricted shares		0.4
Total subject to conversion		48.4
Exchange ratio		1.0 x
Converted shares		48.4
Crosstex Energy, Inc. common share price [(1)]	$	37.60
Crosstex Energy, Inc. consideration	$	1,823
Fair value of noncontrolling interest in E2 [(2)]		18
Total Crosstex Energy, Inc. consideration and fair value of noncontrolling interests	$	1,841
Crosstex Energy, LP outstanding units:		
Common units held by public unitholders		75.1
Preferred units held by third party [(3)]		17.1
Restricted units		0.4
Total		92.6
Crosstex Energy, LP common unit price [(4)]	$	30.51
Crosstex Energy, LP common units value	$	2,825
Crosstex Energy, LP outstanding unit options value		4
Total fair value of noncontrolling interests in the Crosstex Energy, LP [(4)]		2,829
Total consideration and fair value of noncontrolling interests	$	4,670

(1) The final purchase price is based on the fair value of Crosstex Energy, Inc.'s common shares as of the closing date, March 7, 2014.
(2) Represents the value of noncontrolling interests related to the General Partner's equity investment in E2.
(3) Crosstex Energy, LP converted the preferred units to common units in February 2014.
(4) The final purchase price is based on the fair value of Crosstex Energy, LP's common units as of the closing date, March 7, 2014.

The allocation of the purchase price is as follows (millions):

Assets acquired:		
Current assets	$	437
Property, plant and equipment		2,438
Intangible assets		569
Equity investment		222
Goodwill (1)		3,283
Other long-term assets		1
Liabilities assumed:		
Current liabilities		(515)
Long-term debt		(1,454)
Deferred income taxes		(210)
Other long-term liabilities		(101)
Total purchase price	$	4,670

(1) Goodwill is the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Goodwill is not amortized and is not deductible for tax purposes.

Pro Forma Financial Information

The following unaudited pro forma financial information has been prepared assuming both the EnLink formation and the GeoSouthern acquisition occurred on January 1, 2014. The pro forma information is not intended to reflect the actual results of operations that would have occurred if the business combination and acquisition had been completed at the dates indicated. In addition, they do not project Devon’s results of operations for any future period.

	Year Ended December 31, 2014 (Millions)	
Total operating revenues	$	20,213
Net earnings	$	1,716
Noncontrolling interests	$	97
Net earnings attributable to Devon	$	1,619
Net earnings per common share attributable to Devon	$	3.94

3. Derivative Financial Instruments

Commodity Derivatives

As of December 31, 2016, Devon had the following open oil derivative positions. The first table presents Devon's oil derivatives that settle against the average of the prompt month NYMEX WTI futures price. The second table presents Devon's oil derivatives that settle against the respective indices noted within the table.

	Price Swaps		Price Collars		
Period	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
Q1-Q4 2017	72,527	$ 54.32	53,245	$ 45.16	$ 57.97
Q1-Q4 2018	2,600	$ 53.38	6,189	$ 46.97	$ 56.97

	Oil Basis Swaps		
Period	Index	Volume (Bbls/d)	Weighted Average Differential to WTI ($/Bbl)
Q1-Q4 2017	Midland Sweet	10,000	$ (0.43)

As of December 31, 2016, Devon had the following open natural gas derivative positions. The first table presents Devon's natural gas derivatives that settle against the Inside FERC first of the month Henry Hub index. The second table presents Devon's natural gas derivatives that settle against the respective indices noted within the table.

	Price Swaps		Price Collars		
Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)	Volume (MMBtu/d)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)
Q1-Q4 2017	189,753	$ 3.13	335,274	$ 2.97	$ 3.38
Q1-Q4 2018	29,705	$ 3.17	19,110	$ 3.20	$ 3.50

	Natural Gas Basis Swaps		
Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Q1-Q4 2017	Panhandle Eastern Pipe Line	150,000	$ (0.34)
Q1-Q4 2017	El Paso Natural Gas	80,000	$ (0.13)
Q1-Q4 2017	Houston Ship Channel	35,000	$ 0.06
Q1-Q4 2017	Transco Zone 4	205,000	$ 0.03
Q1 2018	Panhandle Eastern Pipe Line	50,000	$ (0.29)

As of December 31, 2016, EnLink had the following open derivative positions associated with gas processing and fractionation. EnLink's NGL positions settle by purity product against the average of the prompt month OPIS Mont Belvieu, Texas index. EnLink's natural gas positions settle against the Henry Hub Gas Daily index.

Period	Product	Volume (Total)		Weighted Average Price Paid	Weighted Average Price Received
Q1 2017-Q4 2017	Propane	434	MBbls	Index	$0.55/gal
Q1 2017-Q4 2017	Normal Butane	161	MBbls	Index	$0.70/gal
Q1 2017-Q4 2017	Natural Gas	21,685	MMBtu/d	Index	$3.14/MMbtu

Interest Rate Derivatives

As of December 31, 2016, Devon had the following open interest rate derivative positions:

Notional (Millions)	Rate Received	Rate Paid	Expiration
$ 750	Three Month LIBOR	2.98%	December 2048 (1)
$ 100	1.76%	Three Month LIBOR	January 2019

(1) Mandatory settlement in December 2018.

Financial Statement Presentation

The following table presents the net gains and losses by derivative financial instrument type followed by the corresponding individual consolidated comprehensive statements of earnings caption.

	Year Ended December 31, 2016	2015	2014
	(Millions)		
Commodity derivatives:			
Oil, gas and NGL derivatives	$ (201)	$ 503	$ 1,989
Marketing and midstream revenues	(13)	9	22
Interest rate derivatives:			
Other nonoperating items	(19)	(20)	(1)
Foreign currency derivatives:			
Other nonoperating items	(153)	246	60
Net gains (losses) recognized	$ (386)	$ 738	$ 2,070

The following table presents the derivative fair values by derivative financial instrument type followed by the corresponding individual consolidated balance sheet caption.

	December 31, 2016	December 31, 2015
	(Millions)	
Commodity derivative assets:		
Other current assets	$ 9	$ 34
Other long-term assets	1	1
Interest rate derivative assets:		
Other current assets	1	1
Other long-term assets	—	1
Foreign currency derivative assets:		
Other current assets	—	8
Total derivative assets	$ 11	$ 45
Commodity derivative liabilities:		
Other current liabilities	$ 187	$ 14
Other long-term liabilities	16	4
Interest rate derivative liabilities:		
Other long-term liabilities	41	22
Foreign currency derivative liabilities:		
Other current liabilities	—	8
Total derivative liabilities	$ 244	$ 48

4. Share-Based Compensation

In the second quarter of 2015, Devon's stockholders approved the 2015 Long-Term Incentive Plan. The 2015 Plan replaces the 2009 Long-Term Incentive Plan, as amended. From the effective date of the 2015 Plan, no further awards may be made under the 2009 Plan, and awards previously granted will continue to be governed by the terms of the 2009 Plan. Subject to the terms of the 2015 Plan, awards may be made under the 2015 Plan for a total of 28 million shares of Devon common stock, plus the number of shares available for issuance under the 2009 Plan (including shares subject to outstanding awards under the 2009 Plan that are subsequently forfeited, canceled or expire). The 2015 Plan authorizes the Compensation Committee, which consists of independent, non-management members of Devon's Board of Directors, to grant nonqualified and incentive stock options, restricted stock awards or units, Canadian restricted stock units, performance awards or units and stock appreciation rights to eligible employees. The 2015 Plan also authorizes the grant of nonqualified stock options, restricted stock awards or units and stock appreciation rights to non-employee directors. To calculate the number of shares that may be granted in awards under the 2015 Plan, options and stock appreciation rights represent one share and other awards represent three shares.

Devon also has a stock option plan that was adopted in 2005 under which stock options were issued to certain employees. Options granted under this plan remain exercisable by the employees owning such options, but no new options or restricted stock awards will be granted under this plan.

The table below presents the effects of share-based compensation included in Devon's accompanying consolidated comprehensive statements of earnings. Gross G&A in 2016, 2015 and 2014 includes $24 million, $31 million and $17 million, respectively, of unit-based compensation related to grants made under EnLink's long-term incentive plans.

The vesting for certain share-based awards was accelerated in 2016 in conjunction with the reduction of workforce described in Note 6. Approximately $60 million of associated expense for these accelerated awards is included in restructuring and transaction costs in the accompanying consolidated comprehensive statements of earnings. In 2014, vesting of certain share-based awards was accelerated in conjunction with the divestiture of Devon's Canadian conventional assets. Approximately $15 million of associated expense for these accelerated awards is included in restructuring and transaction costs in the accompanying consolidated comprehensive statements of earnings.

	Year Ended December 31, 2016	2015	2014
		(Millions)	
Gross G&A for share-based compensation	$ 154	$ 225	$ 199
Share-based compensation expense capitalized pursuant to the full cost method of accounting for oil and gas properties	$ 39	$ 63	$ 53
Related income tax benefit	$ 4	$ 45	$ 42

The following table presents a summary of Devon's unvested restricted stock awards and units, performance-based restricted stock awards and performance share units granted under the plans.

	Restricted Stock Awards and Units: Awards and Units	Restricted Stock Awards and Units: Weighted Average Grant-Date Fair Value	Performance-Based Restricted Stock Awards: Awards	Performance-Based Restricted Stock Awards: Weighted Average Grant-Date Fair Value	Performance Share Units: Units	Performance Share Units: Weighted Average Grant-Date Fair Value
			(Thousands, except fair value data)			
Unvested at 12/31/15	4,738	$ 62.49	434	$ 60.48	1,859	$ 76.17
Granted	4,390	$ 19.91	330	$ 19.22	1,388	$ 10.41
Vested	(2,473)	$ 61.44	(179)	$ 59.10	(602)	$ 63.37
Forfeited	(248)	$ 44.38	—	$ —	(41)	$ 43.88
Unvested at 12/31/16	6,407	$ 34.40	585	$ 37.60	2,604 (1)	$ 46.66

(1) A maximum of 5.2 million common shares could be awarded based upon Devon's final TSR ranking.

The following table presents the aggregate fair value of awards and units that vested during the indicated period.

	2016	2015	2014
		(Millions)	
Restricted Stock Awards and Units	$ 73	$ 101	$ 112
Performance-Based Restricted Stock Awards	$ 5	$ 8	$ 10
Performance Share Units	$ 13	$ 22	$ —

The following table presents the unrecognized compensation cost and the related weighted average recognition period associated with unvested awards and units as of December 31, 2016.

	Restricted Stock Awards and Units	Performance-Based Restricted Stock Awards	Performance Share Units
Unrecognized compensation cost (millions)	$ 131	$ 5	$ 21
Weighted average period for recognition (years)	2.3	2.2	1.6

Restricted Stock Awards and Units

Restricted stock awards and units are subject to the terms, conditions, restrictions and limitations, if any, that the Compensation Committee deems appropriate, including restrictions on continued employment. Generally, the service requirement for vesting ranges from one to four years. During the vesting period, recipients of restricted stock awards receive dividends that are not subject to restrictions or other limitations. Devon estimates the fair values of restricted stock awards and units as the closing price of Devon's common stock on the grant date of the award or unit, which is expensed over the applicable vesting period.

Performance-Based Restricted Stock Awards

Performance-based restricted stock awards are granted to certain members of Devon's senior management. Vesting of the awards is dependent on Devon meeting certain internal performance targets and the recipient meeting certain service requirements. Generally, the service requirement for vesting ranges from one to four years. In order for awards to vest, the performance target must be met in the first year, and if met, recipients are entitled to dividends on the awards over the remaining service vesting period. If the performance target and service period requirements are not met, the award does not vest. Devon estimates the fair values of the awards as the closing price of Devon's common stock on the grant date of the award, which is expensed over the applicable vesting period.

Performance Share Units

Performance share units are granted to certain members of Devon's management and senior employees. Each unit that vests entitles the recipient to one share of Devon common stock. The vesting of these units is based on comparing Devon's TSR to the TSR of a predetermined group of fourteen peer companies over the specified three-year performance period. The vesting of units may be between zero and 200% of the units granted depending on Devon's TSR as compared to the peer group on the vesting date.

At the end of the vesting period, recipients receive dividend equivalents with respect to the number of units vested. The fair value of each performance share unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all grants made under the plan: (i) a risk-free interest rate based on U.S. Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of Devon and the designated peer group; and (iii) an estimated ranking of Devon among the designated peer group. The fair value of the unit on the date of grant is expensed over the applicable vesting period. The following table presents the assumptions related to performance share units granted.

	2016	2015	2014
Grant-date fair value	$ 9.24 — $ 10.61	$ 81.99 — $ 85.05	$ 70.18 — $ 81.05
Risk-free interest rate	0.94%	1.06%	0.54%
Volatility factor	37.7%	26.2%	28.8%
Contractual term (years)	2.83	2.89	2.89

Stock Options

In accordance with Devon's incentive plans, the exercise price of stock options granted may not be less than the market value of the stock at the date of grant. In addition, options granted are exercisable during a period established for each grant, which may not exceed eight years from the date of grant. The recipient must pay the exercise price in cash or in common stock, or a combination thereof, at the time that the option is exercised. Generally, the service requirement for vesting ranges from one to four years. The fair value of stock options on the date of grant is expensed over the applicable vesting period. Devon estimates the fair values of stock options granted using a Black-Scholes option valuation model, which requires Devon to make several assumptions, including a volatility factor, dividend yield rate, risk-free interest rate and expected term. No stock options were granted in 2016, 2015 and 2014. The following table presents a summary of Devon's outstanding stock options.

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Intrinsic Value
	(Thousands)		(Years)	(Millions)
Outstanding at December 31, 2015	3,448	$ 67.98		
Expired	(916)	$ 67.75		
Outstanding at December 31, 2016	2,532	$ 68.06	1.87	$ —
Vested and expected to vest at December 31, 2016	2,532	$ 68.06	1.87	$ —
Exercisable at December 31, 2016	2,532	$ 68.06	1.87	$ —

The aggregate intrinsic value of stock options that were exercised during 2015 and 2014 was $0.2 million and $9 million, respectively. As of December 31, 2016, Devon had no unrecognized compensation cost related to unvested stock options.

EnLink Share-Based Awards

The following table presents a summary of the unrecognized compensation cost and the related weighted average recognition period associated with the General Partner's and EnLink's unvested restricted incentive units and performance units as of December 31, 2016.

	General Partner		EnLink	
	Restricted Incentive Units	Performance Units	Restricted Incentive Units	Performance Units
Unrecognized compensation cost (millions)	$ 14	$ 4	$ 14	$ 4
Weighted average period for recognition (years)	1.6	1.8	1.7	1.8

5. Asset Impairments

The following table presents the asset impairments recognized in 2016, 2015 and 2014.

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
U.S. oil and gas assets	$ 2,809	$ 17,992	$ —
Canada oil and gas assets	1,291	1,257	—
Canada goodwill	—	—	1,941
EnLink goodwill	873	1,328	—
EnLink other intangible assets	—	223	—
Other assets	2	20	12
Total asset impairments	$ 4,975	$ 20,820	$ 1,953

Oil and Gas Impairments

Under the full cost method of accounting, capitalized costs of oil and gas properties are subject to a quarterly full cost ceiling test, which is discussed in Note 1.

The oil and gas impairments resulted from declines in the U.S. and Canada full cost ceilings. The lower ceiling values resulted primarily from significant decreases in the 12-month average trailing prices for oil, bitumen, natural gas and NGLs, which significantly reduced proved reserves values and, to a lesser degree, proved reserves. For further information, see Note 22.

Goodwill and Other Intangible Assets Impairments

In 2016 and 2015, Devon recognized goodwill and other intangible assets impairments related to EnLink's business. Additional information regarding the impairments is discussed in Note 12.

In 2014, as a result of its annual impairment test of goodwill, Devon concluded the implied fair value of its Canadian goodwill was zero and wrote off the remaining goodwill.

6. Restructuring and Transaction Costs

The following table summarizes Devon's restructuring liabilities presented in the accompanying consolidated balance sheets.

	Other Current Liabilities	Other Long-term Liabilities	Total
		(Millions)	
Balance as of December 31, 2014	$ 13	$ 7	$ 20
Changes related to prior years' restructurings	—	56	56
Balance as of December 31, 2015	$ 13	$ 63	$ 76
Changes due to 2016 workforce reductions	29	6	35
Changes related to prior years' restructurings	6	(7)	(1)
Balance as of December 31, 2016	$ 48	$ 62	$ 110

Reduction in Workforce

In 2016, Devon recognized employee-related and other costs associated with a reduction in workforce that was made in response to the depressed commodity price environment. The following table summarizes restructuring and transaction costs presented in the accompanying consolidated comprehensive statement of earnings.

	Year Ended December 31, 2016
	(Millions)
2016 reduction in workforce:	
Employee related costs	$ 227
Lease obligations	20
Asset impairments	3
Transaction costs	17
Restructuring and transaction costs	$ 267

Of these employee-related costs, approximately $60 million resulted from accelerated vesting of share-based grants, which are noncash charges. Additionally, approximately $24 million resulted from estimated defined benefit settlements. These cash and noncash charges included estimates for employees released from service during 2016, as well as amounts based on the number of employees impacted by certain of its non-core asset divestitures.

Devon ceased using certain office space that was subject to non-cancellable operating lease arrangements. Consequently, Devon recognized restructuring costs that represent the present value of its future obligations under the leases. Additionally, Devon recognized asset impairment charges for leasehold improvements and furniture associated with the office space it ceased using.

Transaction Costs

In 2016, Devon and EnLink recognized transaction costs primarily associated with the closing of the acquisitions discussed in Note 2.

Prior Years' Restructurings

In 2015, Devon recognized $24 million of employee-related and other costs associated with the reduction in workforce made subsequent to the completion of the Jackfish development projects and a decrease in planned Canadian capital investment resulting from the drop in commodity prices. Devon incurred employee severance, lease obligation and other costs related to the vacated office space as part of the cost reduction plan.

As part of the U.S. corporate headquarters office consolidation, Devon recognized an additional $54 million expense in 2015, due to a lack of demand for vacated office space and the inability to fully sublease remaining office space.

In 2014, Devon recognized $46 million of employee-related and other costs associated with its divestiture of certain Canadian assets. Approximately $15 million of the employee related costs resulted from accelerated vesting of share-based grants, which are noncash charges.

7. Income Taxes

Income Tax Expense (Benefit)

The following table presents Devon's income tax components.

	Year Ended December 31, 2016	2015	2014
		(Millions)	
Current income tax expense (benefit):			
U.S. federal	$ 5	$ (243)	$ 152
Various states	(11)	(8)	18
Canada and various provinces	106	14	307
Total current tax expense (benefit)	100	(237)	477
Deferred income tax expense (benefit):			
U.S. federal	(3)	(5,033)	1,610
Various states	—	(336)	93
Canada and various provinces	(270)	(459)	188
Total deferred tax expense (benefit)	(273)	(5,828)	1,891
Total income tax expense (benefit)	$ (173)	$ (6,065)	$ 2,368

Total income tax expense (benefit) differed from the amounts computed by applying the U.S. federal income tax rate to earnings before income taxes as a result of the following:

	Year Ended December 31, 2016	2015	2014
		(Millions)	
Total income tax expense (benefit)	$ (173)	$ (6,065)	$ 2,368
U.S. statutory income tax rate	35%	35%	35%
Deferred tax asset valuation allowance	(22%)	(4%)	0%
Non-deductible goodwill and intangible impairment	(8%)	(2%)	23%
Change in unrecognized tax benefits	(2%)	0%	1%
Taxation on Canadian operations	(3%)	(1%)	(4%)
State income taxes	1%	1%	2%
Other	3%	0%	1%
Effective income tax rate	4%	29%	58%

Devon and its subsidiaries are subject to U.S. federal income tax as well as income or capital taxes in various state and foreign jurisdictions. Devon's tax reserves are related to tax years that may be subject to examinations by the relevant taxing authority. Devon is under audit in the U.S. and various foreign jurisdictions as part of its normal course of business.

Devon assesses the realizability of its deferred tax assets. If Devon concludes that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the asset is reduced by a valuation allowance. Numerous judgements and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws.

2016

During 2016, Devon's U.S. segment recorded an additional $774 million valuation allowance against its deferred tax assets. The allowance results from continued financial losses resulting from additional full cost impairments in 2016. As of December 31, 2016, the allowance continues to represent a 100% valuation against the U.S. net deferred tax assets. Additionally, the Canadian segment recognized a $71 million partial valuation allowance resulting from continued financial losses. The valuation allowances impacted the effective tax rate and are discussed in the next section.

In the first quarter of 2016, EnLink recorded a goodwill impairment of approximately $873 million. Additionally, during the third quarter of 2016, Devon derecognized $197 million of goodwill related to its U.S. operations in conjunction with the divestiture of certain non-core U.S upstream oil and gas assets. These impairments are not deductible for purposes of calculating income tax and, therefore, impact the effective tax rate.

2015

In the third and fourth quarters of 2015, EnLink recorded goodwill and intangibles impairments of approximately $1.6 billion, which impacted the effective tax rate.

During 2015, Devon recorded approximately $18 billion of oil and gas impairments related to its U.S. operations. These impairments resulted in deferred tax assets against which Devon recognized a $967 million valuation allowance.

2014

In the second and fourth quarters of 2014, goodwill was removed in conjunction with the Canadian conventional asset divestitures, and Devon recorded a goodwill impairment in the Canadian reporting unit. These non-deductible goodwill reductions impacted the effective tax rate.

Additionally, during 2014, Devon repatriated to the U.S. $2.8 billion of cash relating to the Canadian asset divestiture. In conjunction with the repatriation, Devon recognized approximately $105 million of additional income tax expense for the full year. Prior to the repatriation, Devon had recognized a $143 million deferred income tax liability associated with the planned repatriation. When the repatriation was made, Devon retained a larger property basis in Canada than was previously estimated, resulting in the incremental tax. After the use of foreign tax credits, the current income tax on the repatriation was $67 million.

Furthermore, Devon completed its divestiture program of certain assets in the U.S. In conjunction with the divestitures, Devon recognized $294 million of current income tax expense. The current tax expense was entirely offset by the recognition of deferred tax benefits.

Devon also recorded a $46 million deferred tax liability in conjunction with the formation of EnLink in 2014.

Deferred Tax Assets and Liabilities

The following table presents the tax effects of temporary differences that gave rise to Devon's deferred tax assets and liabilities.

	December 31, 2016	December 31, 2015
	(Millions)	
Deferred tax assets:		
Property and equipment	$ 685	$ 490
Asset retirement obligations	488	485
Accrued liabilities	130	160
Net operating loss carryforwards	777	175
Pension benefit obligations	98	106
Other	203	162
Total deferred tax assets before valuation allowance	2,381	1,578
Less: valuation allowance	(1,666)	(967)
Net deferred tax assets	715	611
Deferred tax liabilities:		
Property and equipment	(884)	(1,187)
Long-term debt	(53)	(36)
Other	(426)	(271)
Total deferred tax liabilities	(1,363)	(1,494)
Net deferred tax liability	$ (648)	$ (883)

At December 31, 2016, Devon has recognized $777 million of deferred tax assets related to various net operating loss carryforwards available to offset future income taxes. The net operating loss carryforwards consist of $536 million of Canadian carryforwards that expire between 2029 and 2037, $1.5 billion of U.S. federal carryforward that expires in 2036, $689 million of U.S. state carryforwards that expire between 2018 and 2036 and $293 million of carryforwards related to EnLink's operations that expire between 2028 and 2036. In the current environment, Devon expects tax benefits from the Canadian carryforwards to be utilized in 2017 and beyond and EnLink carryforwards to be utilized in 2018 and beyond. Devon currently does not anticipate utilizing the U.S. federal or state net operating loss carryforwards, as indicated by the full valuation allowance position in the U.S. segment. EnLink also has $1 million of deferred tax assets related to alternative minimum tax credits, which have no expiration date and will be available for use against tax on future taxable income.

As a result of Devon's continued financial losses incurred largely by the additional full cost impairments, Devon recorded an additional $630 million of valuation allowance against the U.S. deferred tax assets in 2016 and remains in a full valuation allowance position. Also during 2016, Devon's Canadian segment recorded a $69 million partial valuation allowance due to its continued financial losses. In the event Devon were to determine that it would be able to realize the deferred income tax assets in the future, Devon would adjust the valuation allowance, reducing the provision for income taxes in the period of such adjustment.

As of December 31, 2016, Devon's unremitted foreign earnings from its international operations totaled approximately $1.0 billion. All but $47 million of the $1.0 billion was deemed to be indefinitely reinvested into the development and growth of Devon's Canadian business. Therefore, Devon has not recognized a deferred tax liability for U.S. income taxes associated with such earnings. If such earnings were to be repatriated to the U.S., Devon may be subject to U.S. income taxes and foreign withholding taxes. However, it is not practical to estimate the amount of such additional taxes that may be payable due to the inter-relationship of the various factors involved in making such an estimate.

For the remaining $47 million of unremitted earnings deemed not to be indefinitely reinvested, Devon has recognized a $13 million deferred tax liability associated with such unremitted earnings as of December 31, 2016.

Unrecognized Tax Benefits

The following table presents changes in Devon's unrecognized tax benefits.

	December 31, 2016	December 31, 2015
	(Millions)	
Balance at beginning of year	$ 131	$ 241
Tax positions taken in prior periods	36	(19)
Tax positions taken in current year	—	31
Accrual of interest related to tax positions taken	39	(5)
Settlements	—	(108)
Lapse of statute of limitations	(5)	—
Foreign currency translation	1	(9)
Balance at end of year	$ 202	$ 131

Devon's unrecognized tax benefit balance at December 31, 2016 and 2015 included $68 million and $29 million, respectively, of interest and penalties. If recognized, $202 million of Devon's unrecognized tax benefits as of December 31, 2016 would affect Devon's effective income tax rate. Further, Devon believes that within the next 12 months, it is reasonably possible that certain tax examinations will be resolved by settlement with the taxing authorities. During 2016, Devon recognized $88 million of unrecognized tax benefits, including $36 million of interest, associated with such tax examinations. Included below is a summary of the tax years, by jurisdiction, that remain subject to examination by taxing authorities.

Jurisdiction	Tax Years Open
U.S. Federal	2012-2016
Various U.S. states	2010-2016
Canada Federal	2003-2016
Various Canadian provinces	2003-2016

Certain statute of limitation expirations are scheduled to occur in the next twelve months. However, Devon is currently in various stages of the administrative review process for certain open tax years. In addition, Devon is currently subject to various income tax audits that have not reached the administrative review process.

8. Net Earnings (Loss) Per Share Attributable to Devon

The following table reconciles net earnings (loss) attributable to Devon and weighted-average common shares outstanding used in the calculations of basic and diluted net earnings per share.

	Year Ended December 31,		
	2016	2015	2014
	(Millions, except per share amounts)		
Net earnings (loss):			
Net earnings (loss) attributable to Devon	$ (3,302)	$ (14,454)	$ 1,607
Attributable to participating securities	(2)	(5)	(17)
Basic and diluted earnings (loss)	$ (3,304)	$ (14,459)	$ 1,590
Common shares:			
Common shares outstanding - total	513	412	409
Attributable to participating securities	(6)	(5)	(4)
Common shares outstanding - basic	507	407	405
Dilutive effect of potential common shares issuable	—	—	2
Common shares outstanding - diluted	507	407	407
Net earnings (loss) per share attributable to Devon:			
Basic	$ (6.52)	$ (35.55)	$ 3.93
Diluted	$ (6.52)	$ (35.55)	$ 3.91
Antidilutive options (1)	3	4	3

(1) Amounts represent options to purchase shares of Devon's common stock that are excluded from the diluted net earnings per share calculations because the options are antidilutive.

9. Other Comprehensive Earnings

Components of other comprehensive earnings consist of the following:

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
Foreign currency translation:			
Beginning accumulated foreign currency translation	$ 424	$ 983	$ 1,448
Change in cumulative translation adjustment	45	(621)	(499)
Income tax benefit (expense)	(13)	62	34
Ending accumulated foreign currency translation	456	424	983
Pension and postretirement benefit plans:			
Beginning accumulated pension and postretirement benefits	(194)	(204)	(180)
Net actuarial loss and prior service cost arising in current year	(28)	(5)	(57)
Recognition of net actuarial loss and prior service cost in earnings (1)	26	21	20
Curtailment and settlement of pension benefits	24	—	—
Income tax benefit (expense)	—	(6)	13
Ending accumulated pension and postretirement benefits	(172)	(194)	(204)
Accumulated other comprehensive earnings, net of tax	$ 284	$ 230	$ 779

(1) These accumulated other comprehensive earnings components are included in the computation of net periodic benefit cost, which is a component of G&A on the accompanying consolidated comprehensive statements of earnings. See Note 16 for additional details.

10. Supplemental Information to Statements of Cash Flows

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
Net change in working capital accounts, net of assets and liabilities assumed:			
Accounts receivable	$ (176)	$ 942	$ 128
Income taxes receivable	130	384	(467)
Other current assets	215	(57)	(222)
Accounts payable	(167)	(190)	(68)
Revenues and royalties payable	96	(526)	133
Other current liabilities	(106)	(864)	546
Net change in working capital	$ (8)	$ (311)	$ 50
Interest paid (net of capitalized interest)	$ 566	$ 494	$ 514
Income taxes paid (received)	$ (159)	$ (279)	$ 899

In 2016, Devon's acquisition of certain STACK assets included the noncash issuance of Devon common stock. Further, in 2016, EnLink's acquisition of Anadarko Basin gathering and processing midstream assets included noncash issuance of General Partner common units. Additionally, EnLink's formation of a joint venture during the third quarter of 2016 included non-monetary asset contributions. See Note 2 for additional details.

In 2015, Devon's acquisition of certain Powder River Basin assets included noncash common stock issuance totaling $199 million. EnLink's acquisitions in 2015 also included $360 million of noncash equity.

On March 7, 2014, Devon completed a business combination to form EnLink. With the exception of a $100 million cash payment to noncontrolling interests, the business combination was a non-monetary transaction.

11. Accounts Receivable

Components of accounts receivable include the following:

	December 31, 2016	December 31, 2015
	(Millions)	
Oil, gas and NGL sales	$ 487	$ 362
Joint interest billings	110	211
Marketing and midstream revenues	708	520
Other	69	30
Gross accounts receivable	1,374	1,123
Allowance for doubtful accounts	(18)	(18)
Net accounts receivable	$ 1,356	$ 1,105

12. Goodwill and Other Intangible Assets

Goodwill

The following table presents a summary of Devon's goodwill.

	U.S.	EnLink	Total
		(Millions)	
Balance as of December 31, 2014	$ 2,618	$ 3,685	$ 6,303
Acquired during period	—	57	57
Impairment	—	(1,328)	(1,328)
Balance as of December 31, 2015	$ 2,618	$ 2,414	$ 5,032
Acquired during period	—	2	2
Asset divestitures	(197)	—	(197)
Impairment	—	(873)	(873)
Balance as of December 31, 2016	$ 2,421	$ 1,543	$ 3,964

The following table presents the General Partner's and EnLink's goodwill activity by reporting unit.

	Texas	Louisiana	Oklahoma	Crude and Condensate	General Partner	Total
				(Millions)		
Balance as of December 31, 2014	$ 1,168	$ 787	$ 190	$ 113	$ 1,427	$ 3,685
Acquired during period	28	—	—	29	—	57
Impairment	(492)	(787)	—	(49)	—	(1,328)
Balance as of December 31, 2015	$ 704	$ —	$ 190	$ 93	$ 1,427	$ 2,414
Acquired during period	2	—	—	—	—	2
Impairment	(473)	—	—	(93)	(307)	(873)
Balance as of December 31, 2016	$ 233	$ —	$ 190	$ —	$ 1,120	$ 1,543

Asset Divestitures

In conjunction with the U.S. non-core upstream asset divestitures in 2016 discussed in Note 2, Devon removed $197 million of goodwill, which was allocated to these assets.

Impairment

As further discussed in Note 1, Devon performs an annual impairment test of goodwill at October 31, or more frequently if events or changes in circumstances indicate that the carrying value of a reporting unit may not be recoverable. Sustained weakness in the overall energy sector driven by low commodity prices, together with a decline in EnLink's unit price, caused a change in circumstances warranting an interim impairment test of EnLink's reporting units in the first quarter of 2016. Based on that test, EnLink recorded a noncash goodwill impairment.

During 2015, as a result of interim and annual impairment tests of goodwill, noncash goodwill impairments were recorded related to EnLink's Texas, Louisiana and Crude and Condensate reporting units.

Other Intangible Assets

In the third quarter of 2015, Devon recorded a $223 million noncash impairment of intangible assets related to EnLink's Crude and Condensate reporting unit resulting from an assessment of EnLink's customer relationships. Fair value measurements were utilized for the impairment analysis of definite-lived intangible assets, which included discounted cash flow estimates, consistent with those utilized in the goodwill impairment assessment.

The following table presents other intangible assets reported in other long-term assets in the accompanying consolidated balance sheets.

	December 31, 2016	December 31, 2015
	(Millions)	
Customer relationships	$ 1,796	$ 745
Accumulated amortization	(172)	(55)
Net intangibles	$ 1,624	$ 690

The weighted-average amortization period for the customer relationships is 14 years. Amortization expense for intangibles was approximately $117 million, $56 million and $36 million for the years ended 2016, 2015 and 2014, respectively. The remaining aggregate amortization expense is estimated to be approximately $118 million in each of the next five years.

13. Other Current Liabilities

Components of other current liabilities include the following:

	December 31, 2016	December 31, 2015
	(Millions)	
Installment payment - see Note 2	$ 249	$ —
Derivative liabilities	187	22
Accrued interest payable	130	149
Restructuring liabilities	48	13
Other	452	466
Other current liabilities	$ 1,066	$ 650

14. Debt and Related Expenses

See below for a summary of debt instruments and balances. The notes and debentures are senior, unsecured obligations of Devon.

	December 31, 2016	December 31, 2015
	(Millions)	
Devon debt:		
Commercial paper	$ —	$ 626
Floating rate due December 15, 2016	—	350
8.25% due July 1, 2018 (1)(2)	20	125
2.25% due December 15, 2018 (1)	95	750
6.30% due January 15, 2019 (1)	162	700
4.00% due July 15, 2021	500	500
3.25% due May 15, 2022	1,000	1,000
5.85% due December 15, 2025 (1)	485	850
7.50% due September 15, 2027 (1)(2)	73	150
7.875% due September 30, 2031 (1)(3)	1,059	1,250
7.95% due April 15, 2032 (1)	789	1,000
5.60% due July 15, 2041	1,250	1,250
4.75% due May 15, 2042	750	750
5.00% due June 15, 2045	750	750
Net discount on debentures and notes	(30)	(28)
Debt issuance costs	(44)	(57)
Total Devon debt	6,859	9,966
EnLink and General Partner debt:		
Credit facilities	148	414
2.70% due April 1, 2019	400	400
7.125% due June 1, 2022	163	163
4.40% due April 1, 2024	550	550
4.15% due June 1, 2025	750	750
4.85% due July 15, 2026	500	—
5.60% due April 1, 2044	350	350
5.05% due April 1, 2045	450	450
Net premium on debentures and notes	9	13
Debt issuance costs	(25)	(24)
Total EnLink and General Partner debt	3,295	3,066
Total debt	10,154	13,032
Less amount classified as short-term debt (4)	—	976
Total long-term debt	$ 10,154	$ 12,056

(1) These senior notes were included in 2016 tender offer redemptions discussed below.

(2) These instruments were assumed by Devon in April 2003 in conjunction with the merger with Ocean Energy. The fair value and effective rates of these 8.25% notes and 7.50% notes at the time assumed was $147 million and 5.5%, respectively, and $169 million and 6.5%, respectively.

(3) Issued in October 2001, these are unsecured and unsubordinated obligations of Devon Financing, a wholly owned finance subsidiary of Devon. These instruments are fully and unconditionally guaranteed by Devon.

(4) 2015 short-term debt consists of commercial paper balances and floating rate debt that was retired upon maturity in December 2016.

Debt maturities as of December 31, 2016, excluding debt issuance costs, premiums and discounts, are as follows (millions):

2017	$	—
2018		115
2019		590
2020		120
2021		500
Thereafter		8,919
Total	$	10,244

Credit Lines

Devon has a $3.0 billion Senior Credit Facility. The facility matures as follows: $30 million on October 24, 2017, $164 million on October 24, 2018 and the remaining $2.8 billion on October 24, 2019. Amounts borrowed under the Senior Credit Facility may, at the election of Devon, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. However, Devon may elect to borrow at the prime rate. The Senior Credit Facility currently provides for an annual facility fee of $7.6 million. As of December 31, 2016, Devon had $140 million in outstanding letters of credit, including $57 million in outstanding letters of credit under the Senior Credit Facility. There were no borrowings under the Senior Credit Facility as of December 31, 2016.

The Senior Credit Facility contains only one material financial covenant. This covenant requires Devon's ratio of total funded debt to total capitalization, as defined in the credit agreement, to be no greater than 65%. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in the accompanying consolidated financial statements. Also, total capitalization is adjusted to add back noncash financial write-downs such as asset impairments. As of December 31, 2016, Devon was in compliance with this covenant with a debt-to-capitalization ratio of 18.7%.

Commercial Paper

Devon's Senior Credit Facility supports its $3.0 billion of short-term credit under its commercial paper program. Commercial paper debt generally has a maturity of between 1 and 90 days, although it can have a maturity of up to 365 days, and bears interest at rates agreed to at the time of the borrowing. The interest rate is generally based on a standard index such as the Federal Funds Rate, LIBOR or the money market rate as found in the commercial paper market. During 2016, Devon reduced commercial paper borrowings by $626 million. As of December 31, 2016, Devon had no outstanding commercial paper borrowings.

Retirement of Senior Notes

During 2016, Devon completed tender offers to repurchase $2.1 billion of debt securities, using proceeds from the asset divestitures discussed in Note 2. Devon recognized a loss on early retirement of debt, primarily consisting of $265 million in cash retirement costs and other fees. These costs, along with other minimal noncash charges associated with retiring the debt, are included in net financing costs in the consolidated comprehensive statements of earnings.

In November 2014, Devon redeemed $1.9 billion of senior notes prior to their scheduled maturity, primarily with proceeds received from asset divestitures. Devon recognized a loss on the early retirement of debt, primarily consisting of $40 million in cash retirement costs and other noncash charges. These costs are included in net financing costs in the consolidated comprehensive statement of earnings.

Issuance of Senior Notes

In December 2015, in conjunction with the announcement of the Powder River Basin and STACK acquisitions, Devon issued $850 million of 5.85% senior notes due 2025 that are unsecured and unsubordinated obligations. Devon used the net proceeds to partially fund the cash portion of these acquisitions.

In June 2015, Devon issued $750 million of 5.0% senior notes due 2045 that are unsecured and unsubordinated obligations. Devon used the net proceeds to repay the floating rate senior notes that matured on December 15, 2015, as well as outstanding commercial paper balances.

EnLink Debt

All of EnLink's and the General Partner's debt is non-recourse to Devon.

EnLink has a $1.5 billion unsecured revolving credit facility that will mature on March 6, 2020. As of December 31, 2016, there were $12 million in outstanding letters of credit and $120 million outstanding borrowings, with a weighted-average borrowing rate of 2.3%, under the $1.5 billion credit facility. The General Partner has a $250 million revolving credit facility that will mature on March 7, 2019. As of December 31, 2016, the General Partner had $28 million outstanding borrowings under the $250 million credit facility at a weighted average borrowing rate of 3.4%. EnLink and the General Partner were in compliance with all financial covenants in their respective credit facilities as of December 31, 2016.

In July 2016, EnLink issued $500 million of 4.85% unsecured senior notes due 2026. EnLink used the net proceeds to repay outstanding borrowings under its revolving credit facility and for general partnership purposes.

In May 2015, EnLink issued $900 million principal amount of unsecured senior notes, consisting of $750 million principal amount of its 4.15% senior notes due 2025 and an additional $150 million principal amount of its 5.05% senior notes due 2045. EnLink used the net proceeds to repay outstanding revolving credit facility borrowings, for capital expenditures and for general operations.

Net Financing Costs

The following schedule includes the components of net financing costs.

	Year Ended December 31, 2016	2015	2014
		(Millions)	
Devon net financing costs:			
Interest based on debt outstanding	$ 488	$ 450	$ 468
Early retirement of debt	269	—	48
Capitalized interest	(64)	(54)	(58)
Other	21	14	15
Total Devon net financing costs	714	410	473
EnLink net financing costs:			
Interest based on debt outstanding	144	115	64
Interest accretion on deferred installment payment	52	—	—
Other	(6)	(8)	(11)
Total EnLink net financing costs	190	107	53
Total net financing costs	$ 904	$ 517	$ 526

15. Asset Retirement Obligations

The following table presents the changes in asset retirement obligations.

	Year Ended December 31, 2016	2015
	(Millions)	
Asset retirement obligations as of beginning of period	$ 1,414	$ 1,399
Liabilities incurred and assumed through acquisitions	27	63
Liabilities settled and divested	(324)	(89)
Revision of estimated obligation	66	62
Accretion expense on discounted obligation	75	75
Foreign currency translation adjustment	14	(96)
Asset retirement obligations as of end of period	1,272	1,414
Less current portion	46	44
Asset retirement obligations, long-term	$ 1,226	$ 1,370

During 2016, Devon reduced its asset retirement obligation by $287 million for those obligations that were assumed by purchasers of certain upstream U.S. assets.

16. Retirement Plans

Devon has various non-contributory defined benefit pension plans, including qualified plans and nonqualified plans. The qualified plans provide retirement benefits for certain U.S. and Canadian employees meeting certain age and service requirements. Benefits for the qualified plans are based on the employees' years of service and compensation and are funded from assets held in the plans' trusts.

The nonqualified plans provide retirement benefits for certain employees whose benefits under the qualified plans are limited by income tax regulations. The nonqualified plans' benefits are based on the employees' years of service and compensation. For certain nonqualified plans, Devon has established trusts to fund these plans' benefit obligations. The total value of these trusts was $16 million and $22 million at December 31, 2016 and 2015, respectively and is included in other long-term assets in the accompanying consolidated balance sheets. For the remaining nonqualified plans for which trusts have not been established, benefits are funded from Devon's available cash and cash equivalents.

Devon also has defined benefit postretirement plans that provide benefits for substantially all qualifying U.S. retirees. The plans provide medical and, in some cases, life insurance benefits and are either contributory or non-contributory, depending on the type of plan. Benefit obligations for such plans are estimated based on Devon's future cost-sharing intentions. Devon's funding policy for the plans is to fund the benefits as they become payable with available cash and cash equivalents.

Benefit Obligations and Funded Status

The following table presents the funded status of Devon's qualified and nonqualified pension and postretirement benefit plans. The benefit obligation for pension plans represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated benefit obligation. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated benefit obligation for pension plans was $1.2 billion at December 31, 2016 and 2015. Devon's benefit obligations and plan assets are measured each year as of December 31.

	Pension Benefits		Postretirement Benefits	
	2016	2015	2016	2015
	(Millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 1,308	$ 1,377	$ 23	$ 24
Service cost	15	33	—	1
Interest cost	42	52	1	1
Actuarial loss (gain)	63	(68)	(1)	(2)
Plan amendments	2	—	—	1
Plan curtailments	(31)	—	—	—
Plan settlements	(94)	—	—	—
Foreign exchange rate changes	1	(6)	—	—
Participant contributions	—	—	—	2
Benefits paid	(57)	(80)	(2)	(4)
Benefit obligation at end of year	1,249	1,308	21	23
Change in plan assets:				
Fair value of plan assets at beginning of year	1,059	1,149	—	—
Actual return on plan assets	61	(16)	—	—
Employer contributions	16	11	2	2
Participant contributions	—	—	—	2
Plan settlements	(94)	—	—	—
Benefits paid	(57)	(80)	(2)	(4)
Foreign exchange rate changes	—	(5)	—	—
Fair value of plan assets at end of year	985	1,059	—	—
Funded status at end of year	$ (264)	$ (249)	$ (21)	$ (23)
Amounts recognized in balance sheet:				
Other long-term assets	$ 3	$ 2	$ —	$ —
Other current liabilities	(13)	(12)	(3)	(3)
Other long-term liabilities	(254)	(239)	(18)	(20)
Net amount	$ (264)	$ (249)	$ (21)	$ (23)
Amounts recognized in accumulated other comprehensive earnings:				
Net actuarial loss (gain)	$ 285	$ 302	$ (11)	$ (11)
Prior service cost (credit)	8	14	(5)	(6)
Total	$ 293	$ 316	$ (16)	$ (17)

The plan assets for pension benefits in the table above exclude the assets held in trusts for the nonqualified plans. However, employer contributions for pension benefits in the table above include $13 million and $11 million for 2016 and 2015, respectively, which were funded from the trusts established for the nonqualified plans.

Certain of Devon's pension plans are unfunded and have a combined projected benefit obligation and accumulated benefit obligation of $234 million and $211 million, respectively, at December 31, 2016 and $244 million and $199 million, respectively, at December 31, 2015.

Net Periodic Benefit Cost and Other Comprehensive Earnings

The following table presents the components of net periodic benefit cost and other comprehensive earnings.

	Pension Benefits			Postretirement Benefits		
	2016	2015	2014	2016	2015	2014
	(Millions)					
Net periodic benefit cost:						
Service cost	$ 15	$ 33	$ 30	$ —	$ 1	$ 1
Interest cost	42	52	55	1	1	1
Expected return on plan assets	(55)	(58)	(54)	—	—	—
Curtailment and settlement expense	—	—	1	—	—	—
Recognition of net actuarial loss (gain) (1)	25	20	18	(1)	(1)	(1)
Recognition of prior service cost (1)	3	4	4	(1)	(2)	(2)
Total net periodic benefit cost (2)	30	51	54	(1)	(1)	(1)
Other comprehensive loss (earnings):						
Actuarial loss (gain) arising in current year	26	5	57	—	(1)	—
Prior service cost (credit) arising in current year	2	—	—	—	1	—
Recognition of net actuarial loss, including settlement expense, in net periodic benefit cost (3)	(43)	(20)	(19)	1	1	1
Recognition of prior service cost, including curtailment, in net periodic benefit cost (3)	(9)	(4)	(4)	1	1	2
Total other comprehensive loss (earnings)	(24)	(19)	34	2	2	3
Total recognized	$ 6	$ 32	$ 88	$ 1	$ 1	$ 2

(1) These net periodic benefit costs were reclassified out of other comprehensive earnings in the current period.
(2) Net periodic benefit cost is a component of G&A on the accompanying consolidated comprehensive statements of earnings.
(3) These amounts include restructuring costs that were reclassified out of other comprehensive earnings in the current period. See Note 6 for further discussion.

The estimated net actuarial loss and prior service cost for our pension and postretirement benefits that will be amortized from accumulated other comprehensive earnings into net periodic benefit cost during 2017 are $18 million and $1 million, respectively.

Assumptions

The following table presents the weighted-average actuarial assumptions used to determine obligations and periodic costs.

	Pension Benefits			Postretirement Benefits		
	2016	2015	2014	2016	2015	2014
Assumptions to determine benefit obligations:						
Discount rate	4.07%	4.25%	3.90%	3.46%	3.63%	3.25%
Rate of compensation increase	4.49%	4.49%	4.49%	N/A	N/A	N/A
Assumptions to determine net periodic benefit cost:						
Discount rate	4.39%	3.90%	4.80%	3.63%	3.25%	3.65%
Rate of compensation increase	4.49%	4.49%	4.49%	N/A	N/A	N/A
Expected return on plan assets	5.20%	5.22%	5.42%	N/A	N/A	N/A

Discount rate – Future pension and postretirement obligations are discounted at the end of each year based on the rate at which obligations could be effectively settled, considering the timing of estimated future cash flows related to the plans. This rate is based on high-quality bond yields, after allowing for call and default risk.

At the end of 2015, Devon changed the approach used to measure service and interest costs for pension and other postretirement benefits. For 2015, Devon measured service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016, Devon elected to measure service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows. Devon believes the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of the plan obligations nor the funded status of the plans. The change in the service and interest costs going forward is not expected to be significant. This change has been accounted for as a change in accounting estimate.

Rate of compensation increase – For measurement of the 2016 benefit obligation for the pension plans, a 4.49% compensation increase was assumed.

Expected return on plan assets – The expected rate of return on plan assets was determined by evaluating input from external consultants and economists, as well as long-term inflation assumptions. Devon expects the long-term asset allocation to approximate the targeted allocation. Therefore, the expected long-term rate of return on plan assets is based on the target allocation of investment types. See the pension plan assets section below for more information on Devon's target allocations.

Mortality rate assumptions – In 2014, the Society of Actuaries issued updated versions of its mortality tables and mortality improvement scale, reflecting the increasing life expectancies in the U.S. While not required to strictly adhere to this data, Devon utilized actuary-produced mortality tables and an improvement scale derived from the updated tables and the actuary's best estimate of mortality for the population of participants in Devon's plans.

Other assumptions – For measurement of the 2016 benefit obligation for the other postretirement medical plans, a 7.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017. The rate was assumed to decrease annually to an ultimate rate of 5% in the year 2029 and remain at that level thereafter. A one percentage point change in assumed health care cost trend rates would not have a material impact on periodic benefit cost or benefit obligations.

Pension Plan Assets

Devon's overall investment objective for its pension plans' assets is to achieve stability of the plans' funded status while providing long-term growth of invested capital and income to ensure benefit payments can be funded when required. To assist in achieving this objective, Devon has established certain investment strategies, including target allocation percentages and permitted and prohibited investments, designed to mitigate risks inherent with investing. Derivatives or other speculative investments considered high risk are generally prohibited. Devon's target allocations for its pension plan assets are 70% fixed income, 20% equity and 10% other.

The following tables present the fair values of Devon's pension assets by asset class.

	As of December 31, 2016				
			Fair Value Measurements Using:		
	Actual Allocation	Total	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(Millions)		
Fixed-income securities:					
U.S. Treasury obligations	35%	$ 343	$ 68	$ 275	$ —
Corporate bonds	30%	297	205	92	—
Other bonds	4%	38	38	—	—
Total fixed-income securities	69%	678	311	367	—
Equity securities:					
Global (large, mid, small cap)	17%	171	—	171	—
Other securities:					
Hedge fund and alternative investments	11%	112	—	—	112
Short-term investments	3%	24	8	16	—
Total other securities	14%	136	8	16	112
Total investments	100%	$ 985	$ 319	$ 554	$ 112

	As of December 31, 2015				
			Fair Value Measurements Using:		
	Actual Allocation	Total	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(Millions)		
Fixed-income securities:					
U.S. Treasury obligations	17%	$ 179	$ 88	$ 91	$ —
Corporate bonds	48%	507	371	136	—
Other bonds	3%	35	35	—	—
Total fixed-income securities	68%	721	494	227	—
Equity securities:					
Global (large, mid, small cap)	18%	186	—	186	—
Other securities:					
Hedge fund and alternative investments	11%	120	—	—	120
Short-term investments	3%	32	6	26	—
Total other securities	14%	152	6	26	120
Total investments	100%	$ 1,059	$ 500	$ 439	$ 120

The following methods and assumptions were used to estimate the fair values in the tables above.

Fixed-income securities – Devon's fixed-income securities consist of U.S. Treasury obligations, bonds issued by investment-grade companies from diverse industries and asset-backed securities. These fixed-income securities are actively traded securities that can be redeemed upon demand. The fair values of these Level 1 securities are based upon quoted market prices.

Devon's fixed income securities also include commingled funds that primarily invest in long-term bonds and U.S. Treasury securities. These fixed income securities can be redeemed on demand but are not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by the investment managers.

Equity securities – Devon's equity securities include a commingled global equity fund that invests in large, mid and small capitalization stocks across the world's developed and emerging markets. These equity securities can be redeemed on demand but are not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by the investment managers.

Other securities – Devon's other securities include cash and commingled, short-term investment funds. The short-term investment funds' securities can be redeemed on demand but are not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by investment managers.

Devon's hedge fund and alternative investments include an investment in an actively traded global mutual fund that focuses on alternative investment strategies and a hedge fund of funds that invests both long and short using a variety of investment strategies. Devon's hedge fund of funds is not actively traded, and Devon is subject to redemption restrictions with regards to this investment. The fair value of this Level 3 investment represents the fair value as determined by the hedge fund manager.

The following table presents a summary of the changes in Devon's Level 3 plan assets (millions).

December 31, 2014	$ 112
Purchases	5
Investment returns	3
December 31, 2015	120
Investments sold	(12)
Investment returns	4
December 31, 2016	$ 112

Expected Cash Flows

The table below presents contributions expected to be made to Devon's qualified plans, nonqualified plans and postretirement plans. Of the benefits expected to be paid in 2017, $13 million of pension benefits is expected to be funded from the trusts established for the nonqualified plans, and the $3 million of postretirement benefits is expected to be funded from Devon's available cash and cash equivalents. Expected employer contributions and benefit payments for other postretirement benefits are presented net of employee contributions.

	Pension Benefits	Postretirement Benefits
	(Millions)	
2017	$ 60	$ 3
2018	$ 61	$ 3
2019	$ 62	$ 3
2020	$ 64	$ 2
2021	$ 67	$ 2
2022 to 2026	$ 374	$ 7

Defined Contribution Plans

Independent of EnLink, Devon maintains defined contribution plans covering its employees in the U.S. and Canada. Such plans include Devon's 401(k) plan, enhanced contribution plan and Canadian pension and savings plan. Contributions are primarily based upon percentages of annual compensation and years of service. In addition, each plan is subject to regulatory limitations by each respective government. EnLink also maintains a 401(k) plan covering eligible employees. The following table presents expense related to these defined contribution plans.

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
401(k) and enhanced contribution plans	$ 53	$ 63	$ 49
Canadian pension and savings plans	11	16	20
Total	$ 64	$ 79	$ 69

17. Stockholders' Equity

The authorized capital stock of Devon consists of 1.0 billion shares of common stock, par value $0.10 per share, and 4.5 million shares of preferred stock, par value $1.00 per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors.

Common Stock Issued

In January 2016, Devon issued approximately 23 million shares of common stock in conjunction with the STACK asset acquisition discussed in Note 2. Additionally, in February 2016, Devon issued 79 million shares of common stock to the public, inclusive of 10 million shares sold as part of the underwriters' option. Net proceeds from the offering were $1.5 billion.

In December 2015, Devon issued approximately 7 million shares of common stock as part of the Powder River Basin asset acquisition discussed in Note 2.

Dividends

The table below summarizes the dividends Devon paid on its common stock.

	Amounts (Millions)	Rate (Per Share)
Year Ended 2016:		
First quarter 2016	$ 125	$ 0.24
Second quarter 2016	33	$ 0.06
Third quarter 2016	32	$ 0.06
Fourth quarter 2016	31	$ 0.06
Total year-to-date	$ 221	
Year Ended 2015:		
First quarter 2015	$ 99	$ 0.24
Second quarter 2015	98	$ 0.24
Third quarter 2015	99	$ 0.24
Fourth quarter 2015	100	$ 0.24
Total year-to-date	$ 396	
Year Ended 2014:		
First quarter 2014	$ 90	$ 0.22
Second quarter 2014	99	$ 0.24
Third quarter 2014	98	$ 0.24
Fourth quarter 2014	99	$ 0.24
Total year-to-date	$ 386	

18. Noncontrolling Interests

Subsidiary Equity Transactions

During the first quarter of 2016, EnLink issued common units in conjunction with the Tall Oak acquisition discussed in Note 2. Through its equity distribution agreements, EnLink has the ability to sell common units through an "at the market" equity offering program. During 2016, 2015 and 2014, EnLink issued and sold approximately 10.0 million, 1.3 million and 14.8 million common units through its at the market program and general public offerings, generating net proceeds of $167 million, $25 million and $410 million, respectively. Furthermore, in October 2015, EnLink issued approximately 2.8 million common units in a private placement transaction with the General Partner, generating approximately $50 million in proceeds. In 2015, Devon conducted an underwritten secondary public offering of 26.2 million common units representing limited partner interests in EnLink, raising net proceeds of $654 million. As a result of these transactions and EnLink's acquisition and dropdown activity discussed further in Note 2, the table below shows the ownership interest activity in the General Partner and EnLink since inception.

	EnLink			General Partner	
Ownership interest as of	Devon	Non-Devon Unitholders	General Partner	Devon	Non-Devon Unitholders
March 7, 2014	52%	41%	7%	70%	30%
December 31, 2014	49%	43%	8%	70%	30%
December 31, 2015	28%	45%	27%	70%	30%
December 31, 2016	24%	53%	23%	64%	36%

Distributions to Noncontrolling Interests

In conjunction with the formation of the General Partner in 2014, Devon made a payment of $100 million to noncontrolling interests. Furthermore, EnLink and the General Partner distributed $304 million, $254 million and $135 million to non-Devon unitholders during 2016, 2015 and 2014, respectively.

19. Commitments and Contingencies

Devon is party to various legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to Devon and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, Devon's estimates of the outcomes of such matters and its experience in contesting, litigating and settling similar matters. None of the actions are believed by management to involve future amounts that would be material to Devon's financial position or results of operations after consideration of recorded accruals. Actual amounts could differ materially from management's estimates.

Royalty Matters

Numerous natural gas producers and related parties, including Devon, have been named in various lawsuits alleging royalty underpayments. The suits allege that the producers and related parties used below-market prices, made improper deductions, used improper measurement techniques and entered into gas purchase and processing arrangements with affiliates that resulted in underpayment of royalties in connection with oil, natural gas and NGLs produced and sold. Devon is also involved in governmental agency proceedings and is subject to related contracts and regulatory controls in the ordinary course of business, some that may lead to additional royalty claims. Devon does not currently believe that it is subject to material exposure with respect to such royalty matters.

Environmental Matters

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act and similar state statutes. In response to liabilities associated with these activities, loss accruals primarily consist of estimated uninsured remediation costs. Devon's monetary exposure for environmental matters is not expected to be material.

Other Matters

Devon is involved in other various legal proceedings incidental to its business. However, to Devon's knowledge, there were no other material pending legal proceedings to which Devon is a party or to which any of its property is subject.

Commitments

The following table presents Devon's commitments that have initial or remaining noncancelable terms in excess of one year as of December 31, 2016.

Year Ending December 31,	Purchase Obligations	Drilling and Facility Obligations	Operational Agreements	Office and Equipment Leases	EnLink Obligations
		(Millions)			
2017	$ 609	$ 76	$ 1,145	$ 50	$ 50
2018	649	66	1,134	85	51
2019	762	67	627	83	33
2020	748	57	457	59	18
2021	181	37	285	39	17
Thereafter	—	85	2,667	55	102
Total	$ 2,949	$ 388	$ 6,315	$ 371	$ 271

Purchase obligation amounts represent contractual commitments primarily to purchase condensate at market prices for use at Devon's heavy oil projects in Canada. Devon has entered into these agreements because condensate is an integral part of the heavy oil transportation process. Any disruption in Devon's ability to obtain condensate could negatively affect its ability to transport heavy oil at these locations. Devon's total obligation related to condensate purchases expires in 2021. The value of the obligation in the table above is based on the contractual volumes and Devon's internal estimate of future condensate market prices.

Devon has certain drilling and facility obligations under contractual agreements with third-party service providers to procure drilling rigs and other related services for developmental and exploratory drilling and facilities construction. The value of the drilling obligations reported is based on gross contractual value.

Devon has certain operational agreements whereby Devon has committed to transport or process certain volumes of oil, gas and NGLs for a fixed fee. Devon has entered into these agreements to aid the movement of its production to downstream markets.

Devon leases certain office space and equipment under operating lease arrangements. Total rental expense included in G&A under operating leases, net of sublease income, was $78 million, $88 million and $64 million in 2016, 2015 and 2014, respectively.

20. Fair Value Measurements

The following table provides carrying value and fair value measurement information for certain of Devon's financial assets and liabilities. None of the items below are measured using Level 3 inputs. The carrying values of cash, accounts receivable, other current receivables, accounts payable, other current payables and accrued expenses included in the accompanying consolidated balance sheets approximated fair value at December 31, 2016 and December 31, 2015. Therefore, such financial assets and liabilities are not presented in the following table. Additionally, the fair values of oil and gas assets, goodwill and other intangible assets and related impairments are measured as of the impairment date using Level 3 inputs. More information on these items and the pension plan assets is provided in Note 5, Note 12 and Note 16, respectively.

			Fair Value Measurements Using:	
	Carrying Amount	Total Fair Value	Level 1 Inputs	Level 2 Inputs
	(Millions)			
December 31, 2016 assets (liabilities):				
Cash equivalents	$ 1,542	$ 1,542	$ 1,298	$ 244
Commodity derivatives	$ 10	$ 10	$ —	$ 10
Commodity derivatives	$ (203)	$ (203)	$ —	$ (203)
Interest rate derivatives	$ 1	$ 1	$ —	$ 1
Interest rate derivatives	$ (41)	$ (41)	$ —	$ (41)
Debt	$ (10,154)	$ (10,760)	$ —	$ (10,760)
Installment payment	$ (473)	$ (477)	$ —	$ (477)
Capital lease obligations	$ (7)	$ (6)	$ —	$ (6)
December 31, 2015 assets (liabilities):				
Cash equivalents	$ 1,871	$ 1,871	$ 1,471	$ 400
Commodity derivatives	$ 35	$ 35	$ —	$ 35
Commodity derivatives	$ (18)	$ (18)	$ —	$ (18)
Interest rate derivatives	$ 2	$ 2	$ —	$ 2
Interest rate derivatives	$ (22)	$ (22)	$ —	$ (22)
Foreign currency derivatives	$ 8	$ 8	$ —	$ 8
Foreign currency derivatives	$ (8)	$ (8)	$ —	$ (8)
Debt	$ (13,032)	$ (11,927)	$ —	$ (11,927)
Capital lease obligations	$ (17)	$ (16)	$ —	$ (16)

The following methods and assumptions were used to estimate the fair values in the tables above.

Level 1 Fair Value Measurements

Cash equivalents – Amounts consist primarily of U.S. and Canadian treasury securities and money market investments. The fair value approximates the carrying value.

Level 2 Fair Value Measurements

Cash equivalents – Amounts consist primarily of commercial paper and Canadian agency and provincial securities investments. The fair value approximates the carrying value.

Commodity, interest rate and foreign currency derivatives – The fair values of commodity, interest rate and foreign currency derivatives are estimated using internal discounted cash flow calculations based upon forward curves and data obtained from independent third parties for contracts with similar terms or data obtained from counterparties to the agreements.

Debt – Devon's debt instruments do not actively trade in an established market. The fair values of its debt are estimated based on rates available for debt with similar terms and maturity. The fair values of commercial paper and credit facility balances are the carrying values.

Installment payment – The fair value of the EnLink installment payment as of December 31, 2016 was based on Level 2 inputs from third-party market quotations.

Capital lease obligations – The fair value was calculated using inputs from third-party banks.

21. Segment Information

Devon manages its operations through distinct operating segments, which are defined primarily by geographic areas. For financial reporting purposes, Devon aggregates its U.S. operating segments into one reporting segment due to the similar nature of the businesses. However, Devon's Canadian exploration and production operating segment is reported as a separate reporting segment primarily due to the significant differences between the U.S. and Canadian regulatory environments. Devon's U.S. and Canadian segments are both primarily engaged in oil and gas exploration and production activities, and certain information regarding such activities for each segment is included in Note 22.

Devon considers EnLink, combined with the General Partner, to be an operating segment that is distinct from the U.S. and Canadian operating segments. EnLink's operations consist of midstream assets and operations located across the U.S. Additionally, EnLink has a management team that is primarily responsible for capital and resource allocation decisions. Therefore, EnLink is presented as a separate reporting segment.

	U.S. (1)	Canada	EnLink (1)	Eliminations	Total
			(Millions)		
Year Ended December 31, 2016:					
Revenues from external customers	$ 5,722	$ 1,031	$ 3,551	$ —	$ 10,304
Asset dispositions and other	$ 1,367	$ 542	$ (16)	$ —	$ 1,893
Intersegment revenues	$ —	$ —	$ 701	$ (701)	$ —
Depreciation, depletion and amortization	$ 928	$ 360	$ 504	$ —	$ 1,792
Asset impairments	$ 2,809	$ 1,293	$ 873	$ —	$ 4,975
Restructuring and transaction costs	$ 242	$ 19	$ 6	$ —	$ 267
Interest expense	$ 624	$ 181	$ 190	$ (84)	$ 911
Loss before income taxes	$ (2,051)	$ (942)	$ (884)	$ —	$ (3,877)
Income tax benefit	$ (8)	$ (165)	$ —	$ —	$ (173)
Net loss	$ (2,043)	$ (777)	$ (884)	$ —	$ (3,704)
Net earnings (loss) attributable to noncontrolling interests	$ 1	$ —	$ (403)	$ —	$ (402)
Net loss attributable to Devon	$ (2,044)	$ (777)	$ (481)	$ —	$ (3,302)
Property and equipment, net	$ 7,358	$ 2,575	$ 6,257	$ —	$ 16,190
Total assets	$ 12,163	$ 3,536	$ 10,276	$ (62)	$ 25,913
Capital expenditures, including acquisitions	$ 2,880	$ 229	$ 1,082	$ —	$ 4,191
Year Ended December 31, 2015:					
Revenues from external customers	$ 8,360	$ 1,012	$ 3,773	$ —	$ 13,145
Intersegment revenues	$ —	$ —	$ 679	$ (679)	$ —
Depreciation, depletion and amortization	$ 2,220	$ 522	$ 387	$ —	$ 3,129
Asset impairments	$ 18,000	$ 1,257	$ 1,563	$ —	$ 20,820
Restructuring and transaction costs	$ 54	$ 24	$ —	$ —	$ 78
Interest expense	$ 368	$ 94	$ 107	$ (46)	$ 523
Loss before income taxes	$ (18,214)	$ (1,670)	$ (1,384)	$ —	$ (21,268)
Income tax expense (benefit)	$ (5,650)	$ (445)	$ 30	$ —	$ (6,065)
Net loss	$ (12,564)	$ (1,225)	$ (1,414)	$ —	$ (15,203)
Net earnings (loss) attributable to noncontrolling interests	$ 1	$ —	$ (750)	$ —	$ (749)
Net loss attributable to Devon	$ (12,565)	$ (1,225)	$ (664)	$ —	$ (14,454)
Property and equipment, net	$ 8,811	$ 4,590	$ 5,667	$ —	$ 19,068
Total assets	$ 14,550	$ 5,457	$ 9,541	$ (97)	$ 29,451
Capital expenditures, including acquisitions	$ 4,575	$ 680	$ 978	$ —	$ 6,233
Year Ended December 31, 2014:					
Revenues from external customers	$ 14,854	$ 2,063	$ 2,649	$ —	$ 19,566
Asset dispositions and other	$ (5)	$ 1,077	$ —	$ —	$ 1,072
Intersegment revenues	$ —	$ —	$ 859	$ (859)	$ —
Depreciation, depletion and amortization	$ 2,475	$ 560	$ 284	$ —	$ 3,319
Asset impairments	$ 12	$ 1,941	$ —	$ —	$ 1,953
Restructuring and transaction costs	$ —	$ 46	$ —	$ —	$ 46
Interest expense	$ 441	$ 85	$ 54	$ (44)	$ 536
Earnings (loss) before income taxes	$ 4,390	$ (657)	$ 326	$ —	$ 4,059
Income tax expense	$ 1,797	$ 495	$ 76	$ —	$ 2,368
Net earnings (loss)	$ 2,593	$ (1,152)	$ 250	$ —	$ 1,691
Net earnings attributable to noncontrolling interests	$ 1	$ —	$ 83	$ —	$ 84
Net earnings (loss) attributable to Devon	$ 2,592	$ (1,152)	$ 167	$ —	$ 1,607
Property and equipment, net	$ 24,463	$ 6,790	$ 5,043	$ —	$ 36,296
Total assets	$ 31,994	$ 8,509	$ 10,189	$ (124)	$ 50,568
Capital expenditures, including acquisitions	$ 11,214	$ 1,344	$ 1,001	$ —	$ 13,559

(1) Due to Devon's control of EnLink through its control of the General Partner, the acquisition of VEX by EnLink from Devon in the second quarter of 2015 was considered a transfer of net assets between entities under common control, and EnLink was required to recast its financial statements as of December 31, 2015 to include the activities of such assets from the date of common control. Therefore, the results of VEX have been moved from the U.S. segment to the EnLink segment for the recasted periods.

22. Supplemental Information on Oil and Gas Operations (Unaudited)

Supplemental unaudited information regarding Devon's oil and gas activities is presented in this note. The information is provided separately by country.

Costs Incurred

The following tables reflect the costs incurred in oil and gas property acquisition, exploration and development activities.

	Year Ended December 31, 2016		
	U.S.	Canada	Total
		(Millions)	
Property acquisition costs:			
Proved properties	$ 237	$ —	$ 237
Unproved properties	1,356	2	1,358
Exploration costs	345	49	394
Development costs	1,034	109	1,143
Costs incurred	$ 2,972	$ 160	$ 3,132

	Year Ended December 31, 2015		
	U.S.	Canada	Total
		(Millions)	
Property acquisition costs:			
Proved properties	$ 193	$ 2	$ 195
Unproved properties	634	83	717
Exploration costs	478	109	587
Development costs	3,269	402	3,671
Costs incurred	$ 4,574	$ 596	$ 5,170

	Year Ended December 31, 2014		
	U.S.	Canada	Total
		(Millions)	
Property acquisition costs:			
Proved properties	$ 5,210	$ —	$ 5,210
Unproved properties	1,176	1	1,177
Exploration costs	270	52	322
Development costs	4,400	1,063	5,463
Costs incurred	$ 11,056	$ 1,116	$ 12,172

Development costs in the tables above include additions and revisions to Devon's asset retirement obligations.

Pursuant to the full cost method of accounting, Devon capitalizes certain of its G&A that is related to property acquisition, exploration and development activities. Such capitalized expenses, which are included in the costs shown in the preceding tables, were $244 million, $372 million and $376 million in 2016, 2015 and 2014, respectively. Also, Devon capitalizes interest costs incurred and attributable to unproved oil and gas properties and major development projects of oil and gas properties. Capitalized interest expenses, which are included in the costs shown in the preceding tables, were $64 million, $54 million and $45 million in 2016, 2015 and 2014, respectively.

Capitalized Costs

The following tables reflect the aggregate capitalized costs related to oil and gas activities.

	December 31, 2016		
	U.S.	Canada	Total
		(Millions)	
Proved properties	$ 61,401	$ 14,247	$ 75,648
Unproved properties	2,092	1,345	3,437
Total oil and gas properties	63,493	15,592	79,085
Accumulated DD&A	(57,323)	(13,107)	(70,430)
Net capitalized costs	$ 6,170	$ 2,485	$ 8,655

	December 31, 2015		
	U.S.	Canada	Total
		(Millions)	
Proved properties	$ 64,443	$ 13,747	$ 78,190
Unproved properties	1,352	1,232	2,584
Total oil and gas properties	65,795	14,979	80,774
Accumulated DD&A	(58,312)	(11,185)	(69,497)
Net capitalized costs	$ 7,483	$ 3,794	$ 11,277

The following table presents a summary of Devon's oil and gas properties not subject to amortization as of December 31, 2016.

	Costs Incurred In				
	2016	2015	2014	Prior to 2014	Total
			(Millions)		
Acquisition costs	$ 1,176	$ 579	$ 246	$ 464	$ 2,465
Exploration costs	107	134	89	206	536
Development costs	12	—	23	150	185
Capitalized interest	63	52	37	99	251
Total oil and gas properties not subject to amortization	$ 1,358	$ 765	$ 395	$ 919	$ 3,437

Included in the $3.4 billion of oil and gas properties not subject to amortization are approximately $2.9 billion of costs that Devon deems significant for individual assessment. These costs primarily relate to investments in the Pike thermal oil project in Canada, the assets acquired in the STACK play during 2016 and the Powder River Basin assets acquired in 2015. Devon continues to assess its Pike development timeline with its 50% partner. Based on the development plans, Pike costs will begin to be included in the amortization computation when the first phase of this project is fully approved and Devon subsequently begins recognizing the associated proved reserves. Devon is evaluating and plans to develop the newly acquired STACK and Powder River Basin properties over the next four to five years.

Results of Operations

The following tables include revenues and expenses associated with Devon's oil and gas producing activities. They do not include any allocation of Devon's interest costs or general corporate overhead and, therefore, are not necessarily indicative of the contribution to net earnings of Devon's oil and gas operations. Income tax expense has been calculated by applying statutory income tax rates to oil, gas and NGL sales after deducting costs, including DD&A and after giving effect to permanent differences.

	December 31, 2016		
	U.S.	Canada	Total
		(Millions)	
Oil, gas and NGL sales	$ 3,198	$ 984	$ 4,182
Lease operating expenses	(1,123)	(459)	(1,582)
General and administrative expenses	(148)	(20)	(168)
Production and property taxes	(200)	(31)	(231)
Depreciation, depletion and amortization	(817)	(326)	(1,143)
Gains on asset sales	1,351	—	1,351
Asset impairments	(2,809)	(1,291)	(4,100)
Accretion of asset retirement obligations	(49)	(25)	(74)
Income tax benefit	—	245	245
Results of operations	$ (597)	$ (923)	$ (1,520)
Depreciation, depletion and amortization per Boe	$ 4.68	$ 6.65	$ 5.11

	December 31, 2015		
	U.S.	Canada	Total
		(Millions)	
Oil, gas and NGL sales	$ 4,356	$ 1,026	$ 5,382
Lease operating expenses	(1,551)	(553)	(2,104)
General and administrative expenses	(196)	(28)	(224)
Production and property taxes	(309)	(33)	(342)
Depreciation, depletion and amortization	(2,107)	(474)	(2,581)
Asset impairments	(17,992)	(1,257)	(19,249)
Accretion of asset retirement obligations	(47)	(27)	(74)
Income tax benefit	5,547	314	5,861
Results of operations	$ (12,299)	$ (1,032)	$ (13,331)
Depreciation, depletion and amortization per Boe	$ 10.21	$ 11.30	$ 10.40

	December 31, 2014		
	U.S.	Canada	Total
		(Millions)	
Oil, gas and NGL sales	$ 7,867	$ 2,043	$ 9,910
Lease operating expenses	(1,559)	(773)	(2,332)
General and administrative expenses	(153)	(57)	(210)
Production and property taxes	(466)	(37)	(503)
Depreciation, depletion and amortization	(2,365)	(531)	(2,896)
Gains on asset sales	—	1,077	1,077
Accretion of asset retirement obligations	(49)	(39)	(88)
Income tax expense	(1,199)	(568)	(1,767)
Results of operations (1)	$ 2,076	$ 1,115	$ 3,191
Depreciation, depletion and amortization per Boe	$ 11.41	$ 13.80	$ 11.79

(1) During 2014, Devon recognized a Canadian goodwill impairment, which is not reflected in these tables. See Note 5 for additional information.

Proved Reserves

The following tables present Devon's estimated proved reserves by product by country.

	Oil (MMBbls)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2013	229	56	285
Revisions due to prices	(1)	—	(1)
Revisions other than price	(38)	1	(37)
Extensions and discoveries	94	5	99
Purchase of reserves	132	—	132
Production	(48)	(10)	(58)
Sale of reserves	(17)	(29)	(46)
December 31, 2014	351	23	374
Revisions due to prices	(53)	4	(49)
Revisions other than price	(52)	2	(50)
Extensions and discoveries	51	3	54
Purchase of reserves	5	—	5
Production	(60)	(10)	(70)
December 31, 2015	242	22	264
Revisions due to prices	(18)	(2)	(20)
Revisions other than price	(2)	3	1
Extensions and discoveries	36	2	38
Purchase of reserves	8	—	8
Production	(47)	(8)	(55)
Sale of reserves	(25)	—	(25)
December 31, 2016	194	17	211
Proved developed reserves as of:			
December 31, 2013	194	56	250
December 31, 2014	255	23	278
December 31, 2015	203	22	225
December 31, 2016	160	17	177
Proved developed-producing reserves as of:			
December 31, 2013	178	51	229
December 31, 2014	224	19	243
December 31, 2015	192	19	211
December 31, 2016	143	13	156
Proved undeveloped reserves as of:			
December 31, 2013	35	—	35
December 31, 2014	96	—	96
December 31, 2015	39	—	39
December 31, 2016	34	—	34

	Bitumen (MMBbls)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2013	—	552	552
Revisions due to prices	—	(37)	(37)
Revisions other than price	—	18	18
Extensions and discoveries	—	8	8
Production	—	(20)	(20)
December 31, 2014	—	521	521
Revisions due to prices	—	103	103
Revisions other than price	—	(84)	(84)
Extensions and discoveries	—	11	11
Production	—	(31)	(31)
December 31, 2015	—	520	520
Revisions due to prices	—	23	23
Revisions other than price	—	(19)	(19)
Production	—	(40)	(40)
December 31, 2016	—	484	484
Proved developed reserves as of:			
December 31, 2013	—	111	111
December 31, 2014	—	137	137
December 31, 2015	—	219	219
December 31, 2016	—	190	190
Proved developed-producing reserves as of:			
December 31, 2013	—	111	111
December 31, 2014	—	137	137
December 31, 2015	—	219	219
December 31, 2016	—	190	190
Proved undeveloped reserves as of:			
December 31, 2013	—	441	441
December 31, 2014	—	384	384
December 31, 2015	—	301	301
December 31, 2016	—	294	294

	Gas (Bcf)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2013	8,550	758	9,308
Revisions due to prices	191	45	236
Revisions other than price	(299)	4	(295)
Extensions and discoveries	335	8	343
Purchase of reserves	457	—	457
Production	(660)	(41)	(701)
Sale of reserves	(923)	(738)	(1,661)
December 31, 2014	7,651	36	7,687
Revisions due to prices	(1,412)	(9)	(1,421)
Revisions other than price	(3)	(6)	(9)
Extensions and discoveries	171	—	171
Purchase of reserves	17	—	17
Production	(579)	(8)	(587)
Sale of reserves	(37)	—	(37)
December 31, 2015	5,808	13	5,821
Revisions due to prices	(103)	—	(103)
Revisions other than price	628	10	638
Extensions and discoveries	280	—	280
Purchase of reserves	33	—	33
Production	(510)	(7)	(517)
Sale of reserves	(521)	—	(521)
December 31, 2016	5,615	16	5,631
Proved developed reserves as of:			
December 31, 2013	7,707	752	8,459
December 31, 2014	6,948	36	6,984
December 31, 2015	5,694	13	5,707
December 31, 2016	5,361	16	5,377
Proved developed-producing reserves as of:			
December 31, 2013	7,425	680	8,105
December 31, 2014	6,746	34	6,780
December 31, 2015	5,546	13	5,559
December 31, 2016	5,243	16	5,259
Proved undeveloped reserves as of:			
December 31, 2013	843	6	849
December 31, 2014	703	—	703
December 31, 2015	114	—	114
December 31, 2016	254	—	254

	Natural Gas Liquids (MMBbls)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2013	552	23	575
Revisions due to prices	7	1	8
Revisions other than price	2	—	2
Extensions and discoveries	47	—	47
Purchase of reserves	57	—	57
Production	(50)	(1)	(51)
Sale of reserves	(37)	(23)	(60)
December 31, 2014	578	—	578
Revisions due to prices	(119)	—	(119)
Revisions other than price	(6)	—	(6)
Extensions and discoveries	24	—	24
Purchase of reserves	1	—	1
Production	(50)	—	(50)
December 31, 2015	428	—	428
Revisions due to prices	(13)	—	(13)
Revisions other than price	48	—	48
Extensions and discoveries	42	—	42
Purchase of reserves	7	—	7
Production	(42)	—	(42)
Sale of reserves	(45)	—	(45)
December 31, 2016	425	—	425
Proved developed reserves as of:			
December 31, 2013	468	23	491
December 31, 2014	486	—	486
December 31, 2015	411	—	411
December 31, 2016	387	—	387
Proved developed-producing reserves as of:			
December 31, 2013	442	21	463
December 31, 2014	467	—	467
December 31, 2015	393	—	393
December 31, 2016	370	—	370
Proved undeveloped reserves as of:			
December 31, 2013	84	—	84
December 31, 2014	92	—	92
December 31, 2015	17	—	17
December 31, 2016	38	—	38

	Total (MMBoe) (1)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2013	2,205	758	2,963
Revisions due to prices	38	(29)	9
Revisions other than price	(86)	21	(65)
Extensions and discoveries	197	14	211
Purchase of reserves	265	—	265
Production	(207)	(39)	(246)
Sale of reserves	(207)	(176)	(383)
December 31, 2014	2,205	549	2,754
Revisions due to prices	(408)	106	(302)
Revisions other than price	(59)	(83)	(142)
Extensions and discoveries	104	14	118
Purchase of reserves	9	—	9
Production	(206)	(42)	(248)
Sale of reserves	(7)	—	(7)
December 31, 2015	1,638	544	2,182
Revisions due to prices	(48)	21	(27)
Revisions other than price	151	(14)	137
Extensions and discoveries	124	2	126
Purchase of reserves	20	—	20
Production	(174)	(49)	(223)
Sale of reserves	(157)	—	(157)
December 31, 2016	1,554	504	2,058
Proved developed reserves as of:			
December 31, 2013	1,947	315	2,262
December 31, 2014	1,900	165	2,065
December 31, 2015	1,563	243	1,806
December 31, 2016	1,439	210	1,649
Proved developed-producing reserves as of:			
December 31, 2013	1,857	297	2,154
December 31, 2014	1,815	162	1,977
December 31, 2015	1,509	240	1,749
December 31, 2016	1,386	207	1,593
Proved undeveloped reserves as of:			
December 31, 2013	258	443	701
December 31, 2014	305	384	689
December 31, 2015	75	301	376
December 31, 2016	115	294	409

(1) Gas reserves are converted to Boe at the rate of six Mcf per Bbl of oil, based upon the approximate relative energy content of gas and oil. This rate is not necessarily indicative of the relationship of natural gas and oil prices. Bitumen and NGL reserves are converted to Boe on a one-to-one basis with oil.

Proved Undeveloped Reserves

The following table presents the changes in Devon's total proved undeveloped reserves during 2016 (MMBoe).

	U.S.	Canada	Total
Proved undeveloped reserves as of December 31, 2015	75	301	376
Extensions and discoveries	78	—	78
Revisions due to prices	(8)	10	2
Revisions other than price	(1)	(4)	(5)
Sale of reserves	(1)	—	(1)
Conversion to proved developed reserves	(28)	(13)	(41)
Proved undeveloped reserves as of December 31, 2016	115	294	409

Proved undeveloped reserves increased 9% from 2015 to 2016, and the year-end 2016 balance represents 20% of total proved reserves. Drilling and development activities in the STACK and Delaware Basin increased Devon's proved undeveloped reserves by 78 MMBoe. Continued development of Devon's Eagle Ford and Jackfish properties led to the conversion of 41 MMBoe, or 11%, of the 2015 proved undeveloped reserves to proved developed reserves. Costs incurred to develop and convert Devon's proved undeveloped reserves were approximately $586 million for 2016.

A significant amount of Devon's proved undeveloped reserves at the end of 2016 related to its Jackfish operations. At December 31, 2016 and 2015, Devon's Jackfish proved undeveloped reserves were 294 MMBoe and 301 MMBoe, respectively. Development schedules for the Jackfish reserves are primarily controlled by the need to keep the processing plants at their 35 MBbl daily facility capacity. Processing plant capacity is controlled by factors such as total steam processing capacity and steam-oil ratios. Furthermore, development of these projects involves the up-front construction of steam injection/distribution and bitumen processing facilities. Due to the large up-front capital investments and large reserves required to provide economic returns, the project conditions meet the specific circumstances requiring a period greater than 5 years for conversion to developed reserves. As a result, these reserves are classified as proved undeveloped for more than five years. Currently, the development schedule for these reserves extends through 2029. At the end of 2016, approximately 199 MMBoe of proved undeveloped reserves at Jackfish have remained undeveloped for five years or more since the initial booking. No other projects have proved undeveloped reserves that have remained undeveloped more than five years from the initial booking of the reserves. Furthermore, approximately 119 MMBoe of proved undeveloped reserves at Jackfish will require in excess of five years, from the date of this filing, to develop.

Price Revisions

Reserves decreased 27 MMBoe and 302 MMBoe during 2016 and 2015, respectively, primarily due to lower commodity prices for oil, bitumen and gas. The lower bitumen price increased Canadian reserves due to the decline in royalties, which increases Devon's after-royalty volumes.

In 2014, price revisions increased Devon's total proved reserves less than 1% due to higher commodity prices.

Revisions Other Than Price

Total revisions other than price in 2016 primarily related to Devon's evaluation of certain dry gas regions and NGLs, with the largest revisions being made in the Barnett Shale and STACK (Cana-Woodford Shale). Revisions other than price for 2015 primarily related to evaluations of Eagle Ford and Jackfish. Negative revisions other than price at Jackfish were primarily due to a refined reserves methodology that resulted in a reduced recovery factor. Revisions other than price in 2014 primarily related to Devon's evaluation of certain dry gas regions, with the largest revisions being made in the Cana-Woodford Shale and Barnett Shale.

Extensions and Discoveries

2016 – Of the 126 MMBoe of extensions and discoveries, 97 MMBoe related to STACK, 18 MMBoe related to the Delaware Basin and 7 MMBoe related to the Eagle Ford.

The 2016 extensions and discoveries included 74 MMBoe related to additions from Devon's infill drilling activities, primarily consisting of 73 MMBoe related to STACK.

2015 – Of the 118 MMBoe of extensions and discoveries, 38 MMBoe related to the Delaware Basin, 30 MMBoe related to the Anadarko Basin, 21 MMBoe related to the Eagle Ford and 11 MMBoe related to Jackfish.

The 2015 extensions and discoveries included 13 MMBoe related to additions from Devon's infill drilling activities, primarily consisting of 11 MMBoe at Jackfish.

2014 – Of the 211 MMBoe of extensions and discoveries, 70 MMBoe related to the Permian Basin, 54 MMBoe related to the Eagle Ford, 36 MMBoe related to the Barnett Shale, 14 MMBoe related to the Anadarko Basin, 8 MMBoe related to Jackfish and 14 MMBoe related to the Mississippian-Woodford Trend.

The 2014 extensions and discoveries included 5 MMBoe related to additions from Devon's infill drilling activities, primarily consisting of 4 MMBoe at the Permian Basin.

Purchase of Reserves

2016 – Primarily related to Devon's acquisition in the STACK play.

2015 – Primarily related to Devon's acquisition in the Powder River Basin.

2014 – Of the 265 MMBoe of reserves purchases, 246 MMBoe related to Devon's GeoSouthern acquisition in the Eagle Ford.

Sale of Reserves

2016 – The 157 MMBoe of reserves sales related to Devon's non-core upstream asset divestitures discussed further in Note 2.

2015 – The 7 MMBoe of reserves sales related to Devon's asset divestitures in the San Juan Basin.

2014 – The 383 MMBoe of reserves sales related to Devon's asset divestitures in the U.S. and Canada.

Standardized Measure

The following tables reflect Devon's standardized measure of discounted future net cash flows from its proved reserves.

	Year Ended December 31, 2016		
	U.S.	Canada	Total
		(Millions)	
Future cash inflows	$ 22,847	$ 9,672	$ 32,519
Future costs:			
Development	(2,784)	(2,201)	(4,985)
Production	(14,484)	(6,287)	(20,771)
Future income tax expense	—	(57)	(57)
Future net cash flow	5,579	1,127	6,706
10% discount to reflect timing of cash flows	(2,128)	(380)	(2,508)
Standardized measure of discounted future net cash flows	$ 3,451	$ 747	$ 4,198

	Year Ended December 31, 2015		
	U.S.	Canada	Total
		(Millions)	
Future cash inflows	$ 27,398	$ 13,047	$ 40,445
Future costs:			
Development	(3,306)	(2,759)	(6,065)
Production	(17,251)	(6,891)	(24,142)
Future income tax expense	—	(475)	(475)
Future net cash flow	6,841	2,922	9,763
10% discount to reflect timing of cash flows	(1,973)	(1,102)	(3,075)
Standardized measure of discounted future net cash flows	$ 4,868	$ 1,820	$ 6,688

	Year Ended December 31, 2014		
	U.S.	Canada	Total
		(Millions)	
Future cash inflows	$ 75,847	$ 31,371	$ 107,218
Future costs:			
Development	(7,168)	(3,619)	(10,787)
Production	(29,740)	(14,232)	(43,972)
Future income tax expense	(11,021)	(3,026)	(14,047)
Future net cash flow	27,918	10,494	38,412
10% discount to reflect timing of cash flows	(12,819)	(5,119)	(17,938)
Standardized measure of discounted future net cash flows	$ 15,099	$ 5,375	$ 20,474

Future cash inflows, development costs and production costs were computed using the same assumptions for prices and costs that were used to estimate Devon's proved oil and gas reserves at the end of each year. For 2016 estimates, Devon's future realized prices were assumed to be $37.37 per Bbl of oil, $15.74 per Bbl of bitumen, $1.98 per Mcf of gas and $9.91 per Bbl of NGLs. Of the $5.0 billion of future development costs as of the end of 2016, $0.4 billion, $0.8 billion and $0.5 billion are estimated to be spent in 2017, 2018 and 2019, respectively.

Future development costs include not only development costs but also future asset retirement costs. Included as part of the $5.0 billion of future development costs are $1.3 billion of future asset retirement costs. The future income tax expenses have been computed using statutory tax rates, giving effect to allowable tax deductions and tax credits under current laws.

The principal changes in Devon's standardized measure of discounted future net cash flows are as follows:

	Year Ended December 31,		
	2016	2015	2014
		(Millions)	
Beginning balance	$ 6,688	$ 20,474	$ 15,741
Net changes in prices and production costs	(2,128)	(20,756)	2,561
Oil, bitumen, gas and NGL sales, net of production costs	(2,163)	(2,704)	(6,865)
Changes in estimated future development costs	112	1,313	(768)
Extensions and discoveries, net of future development costs	660	1,129	4,836
Purchase of reserves	222	95	6,422
Sales of reserves in place	(560)	(79)	(2,384)
Revisions of quantity estimates	(32)	(1,451)	(746)
Previously estimated development costs incurred during the period	663	2,158	1,933
Accretion of discount	403	567	1,746
Foreign exchange and other	105	(1,254)	(107)
Net change in income taxes	228	7,196	(1,895)
Ending balance	$ 4,198	$ 6,688	$ 20,474

23. Supplemental Quarterly Financial Information (Unaudited)

The following tables present a summary of Devon's unaudited interim results of operations.

	2016				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(Millions, except per share amounts)				
Total revenues and other	$ 2,126	$ 2,488	$ 4,233	$ 3,350	$ 12,197
Earnings (loss) before income taxes	$ (3,685)	$ (1,745)	$ 1,178	$ 375	$ (3,877)
Net earnings (loss) attributable to Devon	$ (3,056)	$ (1,570)	$ 993	$ 331	$ (3,302)
Basic net earnings (loss) per share attributable to Devon	$ (6.44)	$ (3.04)	$ 1.90	$ 0.63	$ (6.52)
Diluted net earnings (loss) per share attributable to Devon	$ (6.44)	$ (3.04)	$ 1.89	$ 0.63	$ (6.52)

	2015				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(Millions, except per share amounts)				
Total revenues and other	$ 3,265	$ 3,393	$ 3,601	$ 2,886	$ 13,145
Loss before income taxes	$ (5,624)	$ (4,479)	$ (5,623)	$ (5,542)	$ (21,268)
Net loss attributable to Devon	$ (3,599)	$ (2,816)	$ (3,507)	$ (4,532)	$ (14,454)
Basic net loss per share attributable to Devon	$ (8.88)	$ (6.94)	$ (8.64)	$ (11.12)	$ (35.55)
Diluted net loss per share attributable to Devon	$ (8.88)	$ (6.94)	$ (8.64)	$ (11.12)	$ (35.55)

Net Earnings (Loss) Attributable to Devon

The 2016 quarterly results include asset impairments of $3.0 billion (or $6.40 per diluted share), $1.5 billion (or $2.89 per diluted share), $0.3 billion (or $0.61 per diluted share) and $0.1 billion (or $0.24 per diluted share) for the first quarter through the fourth quarter of 2016, respectively, as discussed in Note 5. Additionally, the 2016 quarterly results include gains from asset dispositions of approximately $1.4 billion (or $2.59 per diluted share) and $540 million (or $1.04 per diluted share) during the third and fourth quarter of 2016, respectively, as discussed in Note 2.

The 2015 quarterly results include asset impairments of $5.5 billion (or $13.46 per diluted share), $4.2 billion (or $10.27 per diluted share), $5.9 billion (or $14.41 per diluted share) and $5.3 billion (or $13.09 per diluted share) for the first quarter through the fourth quarter of 2015, respectively, as discussed in Note 5.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

Not Applicable.

Item 9A. ***Controls and Procedure*****s**

Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to Devon, including its consolidated subsidiaries, is made known to the officers who certify Devon's financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation, our principal executive and principal financial officers have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective as of December 31, 2016 to ensure that the information required to be disclosed by Devon in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting for Devon, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of Devon's management, including our principal executive and principal financial officers, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission (the "2013 COSO Framework"). Based on this evaluation under the 2013 COSO Framework, which was completed on February 15, 2017, management concluded that its internal control over financial reporting was effective as of December 31, 2016.

The effectiveness of our internal control over financial reporting as of December 31, 2016 has been audited by KPMG LLP, an independent registered public accounting firm who audited our consolidated financial statements as of and for the year ended December 31, 2016, as stated in their report, which is included under "Item 8. Financial Statements and Supplementary Data" of this report.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the fourth quarter of 2016 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information***

Not Applicable.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 no later than 120 days following the fiscal year ended December 31, 2016.

Item 11. *Executive Compensation*

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 no later than 120 days following the fiscal year ended December 31, 2016.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 no later than 120 days following the fiscal year ended December 31, 2016.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 no later than 120 days following the fiscal year ended December 31, 2016.

Item 14. *Principal Accountant Fees and Services*

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 no later than 120 days following the fiscal year ended December 31, 2016.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) The following documents are filed as part of this report:

1. Consolidated Financial Statements

Reference is made to the Index to Consolidated Financial Statements and Consolidated Financial Statement Schedules appearing at "Item 8. Financial Statements and Supplementary Data" in this report.

2. Consolidated Financial Statement Schedules

All financial statement schedules are omitted as they are inapplicable, or the required information has been included in the consolidated financial statements or notes thereto.

3. Exhibits

Exhibit No.	Description
1.1	Underwriting Agreement, dated February 17, 2016, by and between Devon Energy Corporation ("Registrant") and Goldman, Sachs & Co., as the representative of the several underwriters named therein (incorporated by reference to Exhibit 1.1 to Registrant's Form 8-K filed February 22, 2016; File No. 001-32318).
2.1	Agreement and Plan of Merger dated October 21, 2013, by and among Registrant, Devon Gas Services, L.P., Acacia Natural Gas Corp I, Inc., Crosstex Energy, Inc., New Public Rangers L.L.C., Boomer Merger Sub, Inc. and Rangers Merger Sub, Inc. (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed October 22, 2013; File No. 001-32318).
2.2	Contribution Agreement dated October 21, 2013, by and among Registrant, Devon Gas Corporation, Devon Gas Services, L.P., Southwestern Gas Pipeline, Inc., Crosstex Energy, L.P. and Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 2.2 to Registrant's Form 8-K filed October 22, 2013; File No. 001-32318).
2.3	Purchase and Sale Agreement dated November 20, 2013, among GeoSouthern Intermediate Holdings, LLC, GeoSouthern Energy Corporation (solely with respect to certain sections specified therein), and Devon Energy Production Company, L.P. (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K/A filed May 19, 2014; File No. 001-32318).
2.4	Letter Agreement dated February 28, 2014 amending certain provisions of the Purchase and Sale Agreement dated November 20, 2013 among GeoSouthern Intermediate Holdings, LLC, GeoSouthern Energy Corporation and Devon Energy Production Company, L.P (incorporated by reference to Exhibit 2.4 to Registrant's Form 10-K filed February 20, 2015; File No. 001-32318).
3.1	Registrant's Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 of Registrant's Form 10-K filed February 21, 2013; File No. 001-32318).
3.2	Registrant's Bylaws (incorporated by reference to Exhibit 3.1 of Registrant's Form 8-K filed January 27, 2016; File No. 001-32318).
4.1	Registration Rights Agreement dated January 7, 2016, among Registrant and EnCap FEx Holdings, LLC, Felix Stack Investments, LLC, Felix STACK Holdings, LLC and the other selling stockholders from time to time party thereto (incorporated by reference to Exhibit 4.1 to Registrant's Form 10-K filed February 17, 2016; File No. 001-32318).

Exhibit No.	Description
4.2	Registration Rights Agreement dated December 17, 2015, among Registrant and NewWoods Petroleum, LLC and the other selling stockholders from time to time party thereto (incorporated by reference to Exhibit 4.2 to Registrant's Form 10-K filed February 17, 2016; File No. 001-32318).
4.3	Indenture, dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed July 12, 2011; File No. 001-32318).
4.4	Supplemental Indenture No. 1, dated as of July 12, 2011, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 4.00% Senior Notes due 2021 and the 5.60% Senior Notes due 2041 (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed July 12, 2011; File No. 001-32318).
4.5	Supplemental Indenture No. 2, dated as of May 14, 2012, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 3.250% Senior Notes due 2022 and the 4.750% Senior Notes due 2042 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed May 14, 2012; File No. 001-32318).
4.6	Supplemental Indenture No. 3, dated as of December 19, 2013, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 2.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed December 19, 2013; File No. 001-32318).
4.7	Supplemental Indenture No. 4, dated as of June 16, 2015, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 5.000% Senior Notes due 2045 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed June 16, 2015; File No. 001-32318).
4.8	Supplemental Indenture No. 5, dated as of December 15, 2015, to Indenture dated as of July 12, 2011, between Registrant and UMB Bank, National Association, as Trustee, relating to the 5.850% Senior Notes due 2025 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed December 15, 2015; File No. 001-32318).
4.9	Indenture, dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York), as Trustee (incorporated by reference to Exhibit 4.1 of Registrant's Form 8-K filed April 9, 2002; File No. 000-30176).
4.10	Supplemental Indenture No. 1, dated as of March 25, 2002, to Indenture dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 7.95% Senior Debentures due 2032 (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed April 9, 2002; File No. 000-30176).
4.11	Supplemental Indenture No. 3, dated as of January 9, 2009, to Indenture dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 6.30% Senior Notes due 2019 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed January 9, 2009; File No. 000-32318).
4.12	Indenture, dated as of October 3, 2001, by and among Devon Financing Company, L.L.C. (f/k/a Devon Financing Corporation, U.L.C.), as Issuer, Registrant, as Guarantor, and The Bank of New York Mellon Trust Company, N.A., originally The Chase Manhattan Bank, as Trustee, relating to the 7.875% Debentures due 2031 (incorporated by reference to Exhibit 4.7 to Registrant's Registration Statement on Form S-4 filed October 31, 2001; File No. 333-68694).
4.13	Indenture, dated as of July 8, 1998, by and among Devon OEI Operating, L.L.C. (as successor to Ocean Energy, Inc.), its Subsidiary Guarantors, and Wells Fargo Bank, N.A. (as successor to Norwest Bank Minnesota, National Association), as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 10.24 to Ocean Energy, Inc.'s Form 10-Q filed August 14, 1998; File No. 001-14252).

Exhibit No.	Description
4.14	First Supplemental Indenture, dated March 30, 1999, to Indenture dated as of July 8, 1998, by and among Devon OEI Operating, L.L.C., its Subsidiary Guarantor, and Wells Fargo Bank, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.5 to Ocean Energy, Inc.'s Form 10-Q filed May 17, 1999; File No. 001-08094).
4.15	Second Supplemental Indenture, dated as of May 9, 2001, to Indenture dated as of July 8, 1998, by and among Devon OEI Operating, L.L.C., its Subsidiary Guarantor, and Wells Fargo Bank, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 99.2 to Ocean Energy, Inc.'s Form 8-K filed May 14, 2001; File No. 033-06444).
4.16	Third Supplemental Indenture, dated January 23, 2006, to Indenture dated as of July 8, 1998, by and among Devon OEI Operating, L.L.C., as Issuer, Devon Energy Production Company, L.P., as Successor Guarantor, and Wells Fargo Bank, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.23 of Registrant's Form 10-K filed March 3, 2006; File No. 001-32318).
4.17	Senior Indenture, dated as of September 1, 1997, between Devon OEI Operating, L.L.C. (as successor to Seagull Energy Corporation) and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York), as Trustee, and related Specimen of 7.50% Senior Notes due 2027 (incorporated by reference to Exhibit 4.4 to Ocean Energy Inc.'s Form 10-K filed March 23, 1998; File No. 001-08094).
4.18	First Supplemental Indenture, dated as of March 30, 1999, to Senior Indenture dated as of September 1, 1997, by and among Devon OEI Operating, L.L.C., its Subsidiary Guarantor, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 7.50% Senior Notes due 2027 (incorporated by reference to Exhibit 4.10 to Ocean Energy, Inc.'s Form 10-Q filed May 17, 1999; File No. 001-08094).
4.19	Second Supplemental Indenture, dated as of May 9, 2001, to Senior Indenture dated as of September 1, 1997, by and among Devon OEI Operating, L.L.C., its Subsidiary Guarantor, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 7.50% Senior Notes due 2027 (incorporated by reference to Exhibit 99.4 to Ocean Energy, Inc.'s Form 8-K filed May 14, 2001; File No. 033-06444).
4.20	Third Supplemental Indenture, dated December 31, 2005, to Senior Indenture dated as of September 1, 1997, by and among Devon OEI Operating, L.L.C., as Issuer, Devon Energy Production Company, L.P., as Successor Guarantor, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 7.50% Senior Notes due 2027 (incorporated by reference to Exhibit 4.27 of Registrant's Form 10-K filed March 3, 2006; File No. 001-32318).
4.21	Indenture, dated as of March 19, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as Trustee (the "EnLink Indenture") (incorporated by reference to Exhibit 4.2 to EnLink Midstream Partners, LP's Form 8-K filed March 21, 2014; File No. 001-36340).†
4.22	First Supplemental Indenture, dated as of March 19, 2014, to the EnLink Indenture, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to EnLink Midstream Partners, LP's Form 8-K filed March 21, 2014; File No. 001-36340).†
4.23	Second Supplemental Indenture, dated as of November 12, 2014, to the EnLink Indenture, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to EnLink Midstream Partners, LP's Form 8-K filed November 12, 2014; File No. 001-36340).†
4.24	Third Supplemental Indenture, dated as of May 12, 2015, to the EnLink Indenture, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to EnLink Midstream Partners, LP's Form 8-K filed May 12, 2015; File No. 001-36340).†

Exhibit No.	Description
4.25	Fourth Supplemental Indenture, dated as of July 14, 2016, to the EnLink Indenture, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to EnLink Midstream Partners, LP's Form 8-K filed July 14, 2016; File No. 001-36340).†
10.1	Credit Agreement, dated as of October 24, 2012, among Registrant, as U.S. Borrower, Devon NEC Corporation and Devon Canada Corporation, as Canadian Borrowers, each lender from time to time party thereto, each L/C Issuer from time to time party thereto, and Bank of America, N.A., as Administrative Agent, Canadian Swing Line Lender and U.S. Swing Line Lender (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K filed October 29, 2012; File No. 001-32318).
10.2	Extension Agreement, dated as of September 3, 2013, to the Credit Agreement dated October 24, 2012, among Registrant, as U.S. Borrower, Devon NEC Corporation and Devon Canada Corporation, as Canadian Borrowers, Devon Financing Company, L.L.C., the consenting lenders, and Bank of America, N.A., as Administrative Agent, Canadian Swing Line Lender and U.S. Swing Line Lender, with respect to Borrower's extension of the Maturity Date from October 24, 2017 to October 24, 2018 (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed November 6, 2013; File No. 001-32318).
10.3	First Amendment to Credit Agreement, dated as of February 3, 2014, to the Credit Agreement dated October 24, 2012, among Registrant, as U.S. Borrower, Devon NEC Corporation and Devon Canada Corporation, as Canadian Borrowers, each lender from time to time party thereto, each L/C Issuer from time to time party thereto, and Bank of America, N.A., as Administrative Agent, Canadian Swing Line Lender and U.S. Swing Line Lender (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K filed February 7, 2014; File No. 001-32318).
10.4	Extension Agreement, dated as of October 17, 2014, to the Credit Agreement dated October 24, 2012, among Registrant, as U.S. Borrower, Devon NEC Corporation and Devon Canada Corporation, as Canadian Borrowers, Devon Financing Company, L.L.C., the consenting lenders, and Bank of America, N.A., as Administrative Agent, Canadian Swing Line Lender and U.S. Swing Line Lender with respect to the extension of the maturity date from October 24, 2018 to October 24, 2019 (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed November 5, 2014; File No. 001-32318).
10.5	Devon Energy Corporation 2015 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registrant's Form S-8 filed June 3, 2015; File No. 333-204666).*
10.6	Devon Energy Corporation 2009 Long-Term Incentive Plan (as amended and restated effective June 6, 2012) (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed June 8, 2012; File No. 001-32318).*
10.7	2013 Amendment (effective as of March 6, 2013) to the Devon Energy Corporation 2009 Long-Term Incentive Plan (as amended and restated effective June 6, 2012) (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed May 1, 2013; File No. 001-32318).*
10.8	Devon Energy Corporation 2005 Long-Term Incentive Plan (incorporated by reference to Appendix A to Registrant's Proxy Statement for the 2005 Annual Meeting of Stockholders filed April 25, 2005; File No. 001-32318).*
10.9	First Amendment to Devon Energy Corporation 2005 Long-Term Incentive Plan (incorporated by reference to Appendix A to Registrant's Proxy Statement for the 2006 Annual Meeting of Stockholders filed April 28, 2006; File No. 001-32318).*
10.10	Devon Energy Corporation 2012 Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K, filed June 8, 2012; File No. 001-32318)*
10.11	Devon Energy Corporation Non-Qualified Deferred Compensation Plan (amended and restated effective as of April 15, 2014) (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed August 6, 2014; File No. 001-32318).*

Exhibit No.	Description
10.12	Amendment 2014-2, executed May 9, 2014, to the Devon Energy Corporation Non-Qualified Deferred Compensation Plan as amended effective April 15, 2014 (incorporated by reference to Exhibit 10.11 to Registrant's Form 10-K, filed February 20, 2015; File No. 001-32318).*
10.13	Amendment 2016-1, executed October 20, 2016, to the Devon Energy Corporation Non-Qualified Deferred Compensation Plan (amended and restated effective April 15, 2014).*
10.14	Devon Energy Corporation Benefit Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.15 to Registrant's Form 10-K, filed February 24, 2012; File No. 001-32318).*
10.15	Amendment 2014-1, executed March 7, 2014, to the Devon Energy Corporation Benefit Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.6 to Registrant's Form 10-Q filed May 9, 2014; File No. 001-32318).*
10.16	Amendment 2015-1, executed April 15, 2015, to the Devon Energy Corporation Benefit Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed May 6, 2015; File No. 001-32318).*
10.17	Amendment 2016-1, executed October 20, 2016, to the Devon Energy Corporation Benefit Restoration Plan (amended and restated effective January 1, 2012).*
10.18	Devon Energy Corporation Defined Contribution Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.16 to Registrant's Form 10-K, filed February 24, 2012; File No. 001-32318).*
10.19	Amendment 2014-1, executed March 7, 2014, to the Devon Energy Corporation Defined Contribution Restoration Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.7 to Registrant's Form 10-Q filed May 9, 2014; File No. 001-32318).*
10.20	Amendment 2016-1, executed October 20, 2016, to the Devon Energy Corporation Defined Contribution Restoration Plan (amended and restated effective January 1, 2012).*
10.21	Devon Energy Corporation Supplemental Contribution Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.17 to Registrant's Form 10-K, filed February 24, 2012; File No. 001-32318).*
10.22	Amendment 2014-1, executed March 7, 2014, to the Devon Energy Corporation Supplemental Contribution Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.8 to Registrant's Form 10-Q filed May 9, 2014; File No. 001-32318).*
10.23	Amendment 2016-1, executed October 20, 2016, to the Devon Energy Corporation Supplemental Contribution Plan (amended and restated effective January 1, 2012).*
10.24	Devon Energy Corporation Supplemental Executive Retirement Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.18 to Registrant's Form 10-K filed February 24, 2012; File No. 001-32318).*
10.25	Amendment 2016-1, executed October 20, 2016, to the Devon Energy Corporation Supplemental Executive Retirement Plan (amended and restated effective January 1, 2012).*
10.26	Devon Energy Corporation Supplemental Retirement Income Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.19 to Registrant's Form 10-K filed February 24, 2012; File No. 001-32318).*
10.27	Amendment 2014-1, executed March 7, 2014, to the Devon Energy Corporation Supplemental Retirement Income Plan (amended and restated effective January 1, 2012) (incorporated by reference to Exhibit 10.9 to Registrant's Form 10-Q filed May 9, 2014; File No. 001-32318).*
10.28	Amendment 2016-1, executed October 20, 2016, to the Devon Energy Corporation Supplemental Retirement Income Plan (amended and restated effective January 1, 2012).*

Exhibit No.	Description
10.29	Devon Energy Corporation Incentive Savings Plan, as amended and restated effective January 1, 2014, executed September 22, 2014 (incorporated by reference to Exhibit 10.21 to Registrant’s Form 10-K, filed February 20, 2015; File No. 001-32318).*
10.30	Amendment 2015-1, executed April 15, 2015, to the Devon Energy Corporation Incentive Savings Plan (amended and restated effective January 1, 2014) (incorporated by reference to Exhibit 10.2 to Registrant’s Form 10-Q filed May 6, 2015; File No. 001-32318).*
10.31	Amendment 2016-1, executed January 5, 2016, to the Devon Energy Corporation Incentive Savings Plan (amended and restated effective January 1, 2014).*
10.32	Amendment 2016-2, executed March 29, 2016, to the Devon Energy Corporation Incentive Savings Plan (amended and restated effective January 1, 2014).*
10.33	Amendment 2016-3, executed October 20, 2016, to the Devon Energy Corporation Incentive Savings Plan (amended and restated effective January 1, 2014).*
10.34	Amendment 2016-4, executed December 20, 2016, to the Devon Energy Corporation Incentive Savings Plan (amended and restated effective January 1, 2014).*
10.35	Amended and Restated Form of Employment Agreement between Registrant and certain executive officers (incorporated by reference to Exhibit 10.19 to Registrant’s Form 10-K filed February 27, 2009; File No. 001-32318).*
10.36	Form of Amendment No. 1 to the Amended and Restated Employment Agreement between Registrant and certain executive officers (incorporated by reference to Exhibit 10.1 to Registrant’s Form 8-K filed April 25, 2011; File No. 001-32318).*
10.37	Form of Employment Agreement between Registrant and certain executive officers (incorporated by reference to Exhibit 10.22 to Registrant’s Form 10-K filed February 28, 2014; File No. 001-32318).*
10.38	Form of Notice of Grant of Performance Restricted Stock Award and Award Agreement under the 2009 Long-Term Incentive Plan (as amended and restated June 6, 2012) between Registrant and certain employees and executive officers for performance based restricted stock awarded (incorporated by reference to Exhibit 10.25 to Registrant’s Form 10-K filed February 28, 2014; File No. 001-32318).*
10.39	Form of Notice of Grant of Performance Restricted Stock Award and Award Agreement under the 2009 Long-Term Incentive Plan (as amended and restated June 6, 2012) between Registrant and certain employees and executive officers for performance based restricted stock awarded (incorporated by reference to Exhibit 10.29 to Registrant’s Form 10-K filed February 20, 2015; File No. 001-32318).*
10.40	Form of Notice of Grant of Performance Restricted Stock Award and Award Agreement under the 2015 Long-Term Incentive Plan between Registrant and David A. Hager for performance based restricted stock awarded (incorporated by reference to Exhibit 10.1 to Registrant’s Form 10-Q filed November 4, 2015; File No. 001-32318).*
10.41	Form of Notice of Grant of Performance Restricted Stock Award and Award Agreement under the 2015 Long-Term Incentive Plan between Registrant and executive officers for performance based restricted stock awarded (incorporated by reference to Exhibit 10.2 to Registrant’s Form 10-Q filed May 4, 2016; File No. 001-32318).*
10.42	Form of Notice of Grant of Performance Share Unit Award and Award Agreement under the 2009 Long-Term Incentive Plan (as amended and restated June 6, 2012) between Registrant and certain employees and executive officers for performance based restricted share units awarded (incorporated by reference to Exhibit 10.28 to Registrant’s Form 10-K filed February 28, 2014; File No. 001-32318).*
10.43	Form of Notice of Grant of Performance Share Unit Award and Award Agreement under the 2009 Long-Term Incentive Plan (as amended and restated June 6, 2012) between Registrant and certain employees and executive officers for performance based restricted share units awarded (incorporated by reference to Exhibit 10.32 to Registrant’s Form 10-K filed February 20, 2015; File No. 001-32318).*

Exhibit No.	Description
10.44	Form of Notice of Grant of Performance Share Unit Award and Award Agreement under the 2015 Long-Term Incentive Plan between Registrant and executive officers for performance based restricted share units awarded (incorporated by reference to Exhibit 10.3 to Registrant's Form 10-Q filed May 4, 2016; File No. 001-32318).*
10.45	Form of Notice of Grant of Incentive Stock Options and Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and certain employees and executive officers for incentive stock options granted (incorporated by reference to Exhibit 10.15 to Registrant's Form 10-K filed February 25, 2011; File No. 001-32318).*
10.46	Form of Notice of Grant of Nonqualified Stock Options and Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and certain employees and executive officers for nonqualified stock options granted (incorporated by reference to Exhibit 10.16 to Registrant's Form 10-K filed February 25, 2011; File No. 001-32318).*
10.47	Form of Non-Management Director Nonqualified Stock Option Award Agreement under the Devon Energy Corporation 2009 Long-Term Incentive Plan between Registrant and all Non-Management Directors for nonqualified stock options granted (incorporated by reference to Exhibit 10.20 to Registrant's Form 10-K filed on February 25, 2010; File No. 001-32318).*
10.48	Form of Notice of Grant of Restricted Stock Award and Award Agreement under the 2009 Long-Term Incentive Plan (as amended and restated June 6, 2012) between Registrant and Thomas L. Mitchell for restricted stock awarded (incorporated by reference to Exhibit 10.18 to Registrant's Form 10-K filed February 25, 2011; File No. 001-32318).*
10.49	Form of Notice of Grant of Restricted Stock Award and Award Agreement under the 2015 Long-Term Incentive Plan between Registrant and all non-management directors for restricted stock awards (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-Q filed August 5, 2015; File No. 001-32318).*
10.50	Form of Letter Agreement amending the restricted stock award agreements and nonqualified stock option agreements under the 2009 Long-Term Incentive Plan and the 2005 Long-Term Incentive Plan between Registrant and J. Larry Nichols, John Richels and Darryl G. Smette (incorporated by reference to Exhibit 10.22 to Registrant's Form 10-K filed February 25, 2011; File No. 001-32318).*
10.51	Form of Amendment to Incentive Stock Option Award Agreements between Registrant and post-retirement eligible executives relating to incentive stock options under the 2009 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.24 to Registrant's Form 10-K filed February 21, 2013; File No. 001-32318).*
10.52	Amendment to Performance Share Unit Award Agreement dated effective September 16, 2015, between Registrant and John Richels to Performance Share Unit Award Agreement dated February 10, 2015 (incorporated by reference to Exhibit 10.43 to Registrant's Form 10-K filed February 17, 2016; File No. 001-32318).*
10.53	Amendment to Performance Restricted Stock Award Agreement dated effective September 16, 2015, between Registrant and John Richels to Performance Restricted Stock Award Agreement dated February 10, 2015 (incorporated by reference to Exhibit 10.44 to Registrant's Form 10-K filed February 17, 2016; File No. 001-32318).*
12	Statement of computations of ratios of earnings to fixed charges.
21	List of Subsidiaries.
23.1	Consent of KPMG LLP.
23.2	Consent of LaRoche Petroleum Consultants, Ltd.
23.3	Consent of Deloitte LLP.

Exhibit No.	Description
31.1	Certification of principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of principal executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Report of LaRoche Petroleum Consultants, Ltd.
99.2	Report of Deloitte LLP.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

† As of December 31, 2016, the aggregate amount of debt issued under the EnLink Indenture, as supplemented, exceeded ten percent of Devon’s consolidated total assets. Devon has not filed any other instruments defining the rights of holders of long-term indebtedness of EnLink, as such instruments do not represent debt exceeding ten percent of the total assets of Devon and its subsidiaries on a consolidated basis. Devon hereby agrees to furnish a copy of any such agreements to the SEC upon request.

* Indicates management contract or compensatory plan or arrangement.

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.

DEVON ENERGY CORPORATION

By: /s/ THOMAS L. MITCHELL
Thomas L. Mitchell
Executive Vice President and
Chief Financial Officer

February 15, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ DAVID A. HAGER David A. Hager	President, Chief Executive Officer and Director (Principal executive officer)	February 15, 2017
/s/ THOMAS L. MITCHELL Thomas L. Mitchell	Executive Vice President and Chief Financial Officer (Principal financial officer)	February 15, 2017
/s/ JEREMY D. HUMPHERS Jeremy D. Humphers	Senior Vice President and Chief Accounting Officer (Principal accounting officer)	February 15, 2017
/s/ JOHN RICHELS John Richels	Chairman of the Board	February 15, 2017
/s/ BARBARA M. BAUMANN Barbara M. Baumann	Director	February 15, 2017
/s/ JOHN E. BETHANCOURT John E. Bethancourt	Director	February 15, 2017
/s/ ROBERT H. HENRY Robert H. Henry	Director	February 15, 2017
/s/ MICHAEL M. KANOVSKY Michael M. Kanovsky	Director	February 15, 2017
/s/ ROBERT A. MOSBACHER, JR. Robert A. Mosbacher, Jr.	Director	February 15, 2017
/s/ DUANE C. RADTKE Duane C. Radtke	Director	February 15, 2017
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	February 15, 2017

Directors

John Richels
Chairman

Barbara M. Baumann (1) (3)

John E. Bethancourt (2) (3) (4)

David A. Hager

Robert H. Henry (1) (3)

Michael M. Kanovsky (1) (4)
Chairman of Reserves Committee

Robert A. Mosbacher Jr. (2) (3)
Lead Director
Chairman of Governance Committee

Duane C. Radtke (2) (4)
Chairman of Compensation Committee

Mary P. Ricciardello (1) (3)
Chairman of Audit Committee

(1) Audit Committee
(2) Compensation Committee
(3) Governance Committee
(4) Reserves Committee

Senior Executives

David A. Hager
President and Chief Executive Officer

Tony D. Vaughn
Chief Operating Officer

Thomas L. Mitchell
Executive Vice President and Chief Financial Officer

R. Alan Marcum
Executive Vice President, Administration

Lyndon C. Taylor
Executive Vice President and General Counsel

Other Executives

Susan E. Alberti
Senior Vice President, Marketing

Tana K. Cashion
Senior Vice President, Human Resources

Rob Dutton
Senior Vice President, Canadian Operations and President of Devon Canada

Richard A. Gideon
Senior Vice President, U.S. Operations

David G. Harris
Senior Vice President, Business Development

Jeremy D. Humphers
Senior Vice President and Chief Accounting Officer

Kevin D. Lafferty
Senior Vice President, U.S. Operations

Bill A. Penhall
Senior Vice President, Exploration and New Ventures

Jeffrey L. Ritenour
Senior Vice President, Corporate Finance, Investor Relations and Treasurer

Michael J. Stover
Senior Vice President, Strategic Services

Other Information

Investor Relations Contacts
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Telephone: (405) 552-4735

Chris Carr, Supervisor Investor Relations
Telephone: (405) 228-2496

Media Contact
John Porretto, Director Corporate Communications
Telephone: (405) 228-7506

Shareholder Assistance
For information about transfer or exchange of shares, dividends, address changes, account consolidation, multiple mailings, lost certificates and Form 1099, contact:

Computershare Trust Company, N.A.
PO Box 43078
Providence, RI 02940-3078
Toll free: (877) 860-5820
Website: www.computershare.com/investor

Royalty Owner Assistance
Telephone: (405) 228-4800
E-mail: DevonDirect@dvn.com

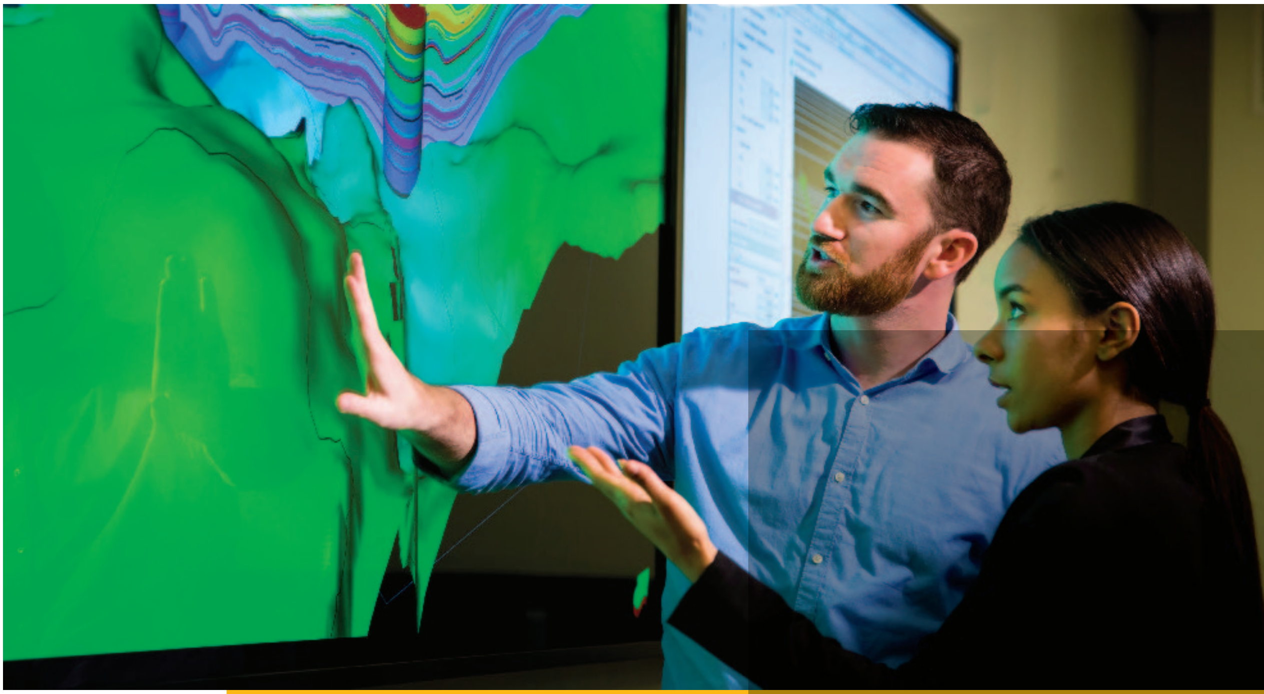
Annual Meeting
Our annual shareholders' meeting will be held at 8 a.m. Central Time on Wednesday, June 7, 2017, at the Devon Energy Center Auditorium, 333 W. Sheridan Avenue, Oklahoma City, OK.

Independent Auditors
KPMG LLP
Oklahoma City, OK

Stock Trading Data
Devon Energy Corporation's common stock is traded on the New York Stock Exchange (symbol: DVN). There are approximately 7,800 shareholders of record.

Additional Information
This report, Devon's Corporate Social Responsibility Report and other information about the company are available at www.devonenergy.com.

Forward-Looking Statements
See information regarding forward-looking statements on page five of this report.



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@DevonEnergy

devon