Devon Energy

2015 Letter to Shareholders and Form 10-K

Commitment Runs Deep

devon

Letter to Shareholders

2015 was a year of extreme price volatility for our industry. The success of U.S. resource plays, combined with unwavering OPEC production, drove world oil markets to be oversupplied by more than a million barrels a day. This imbalance pushed the average benchmark WTI oil price down nearly 50 percent during the year. With natural gas prices similarly depressed, cash flows across the E&P sector were severely constrained. However, the good news is that fundamental supply and demand dynamics appear to be improving. Persistent growth in global oil demand coupled with declines in production, led by North American resource plays, are bringing balance back to the market.

Generating top-tier operating results

In spite of these tough economic conditions, Devon's strategy of operating in North America's best resource plays with a sharp focus on best-in-class execution is generating top-tier results. We are seeing higher production rates, lower capital costs and lower operating expenses across the company's portfolio. This strong performance has guided the company to consistently exceed well type-curve expectations and driven peer-leading results.

Our strong operating performance produced some notable highlights in 2015:

- Record oil production – 275,000 barrels a day, up 28 percent
- Greater production value – reduced field-level operating costs by nearly $400 million
- Lower capital costs – achieved $500 million of savings from original budget expectations

Enhancing our world-class portfolio

Looking beyond our reported results, it was also a pivotal year for Devon's asset portfolio. Late in the year we moved decisively to materially expand our position in the Oklahoma Anadarko Basin. Also known as the STACK, this in our view is the best emerging development opportunity in North America. I have unwavering conviction that this strategic acquisition will further Devon's ability to deliver differentiating operating results for many years to come.

The quality of our go-forward asset base is unmatched. Our franchise properties in the STACK and Delaware Basin have the scale and scope to deliver long-term, sustainable growth. Complementing these are some of the best cash-flow-generating assets in the U.S. – the Barnett Shale and Eagle Ford. With the depth, diversity and quality of our premier portfolio, we are well positioned to create significant value for our shareholders.

Responding with caution

As we look to 2016, given the low commodity-price environment and the uncertain duration of this downturn, our top priority is to protect the balance sheet by spending within our available cash flow. We also see no reason to accelerate production growth into weak commodity markets, so we have prudently reduced our capital activity by 75 percent from last year.

To ensure the continued strength of our investment grade balance sheet, we also trimmed more than $1 billion from our cost structure and have a divestiture program under way with the intent to monetize $2 billion to $3 billion of assets. With our financial strength and flexibility intact, we are ready to move quickly once the markets and economics turn favorable again for increased investment.

A culture of success

Regardless of the business environment, Devon has a long tradition of doing its work the right way. This commitment remains strong today and starts with working safely. But creating a culture of safety is just the beginning for us when it comes to doing things the right way. Our efforts to care for the land, preserve wildlife, conserve water, reduce emissions and be a good neighbor continue to be a priority and our efforts have been widely recognized.

When I look to the coming years, I have every reason to be optimistic about Devon's future. We have a great collection of assets, a strong commitment to superior execution and one of the more advantaged capital structures in the E&P space. As we continue to execute on our disciplined business plan, we are well positioned to consistently generate outsized returns for our shareholders.

David A. Hager

Dave Hager
President and CEO

April 7, 2016

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, 2015

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, 2015 was approximately $24.3 billion, based upon the closing price of $59.49 per share as reported by the New York Stock Exchange on such date. On February 10, 2016, 441.3 million shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2016 annual meeting of stockholders – Part III

DEVON ENERGY CORPORATION
FORM 10-K
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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.

“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.

“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.

“DOE” means Department of Energy.

“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.

“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.

“General Partner” means EnLink Midstream, LLC, the 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.

"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.

"Pre-tax 10% present value" means the present value of Devon's pre-tax future net revenue to be generated from the production of proved reserves, net of estimated production and development costs and site restoration and abandonment charges.

"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.

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This report includes "forward-looking statements" as defined by the SEC. Such statements are 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, 2015 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, including the currently depressed commodity price environment;
- 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 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

Devon is a leading 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. Our portfolio of oil and gas properties provides stable, environmentally responsible production and a platform for future growth. We have doubled our onshore North American oil production since 2010 to more than 275 MBbls per day and have a deep inventory of development opportunities. Devon also produces over 1.6 Bcf of natural gas a day and more than 136 MBbls of NGLs per day.

Additionally, we control EnLink, a leading integrated midstream business with significant size and scale in key operating regions in the U.S. This MLP focuses on providing gathering, transmission, processing, fractionation and marketing to producers of natural gas, NGLs, crude oil and condensate.

A Delaware corporation formed in 1971, we have been publicly held since 1988, and our common stock is listed on the NYSE. Our principal and administrative offices are located at 333 West Sheridan, Oklahoma City, OK 73102-5015 (telephone 405-235-3611). As of December 31, 2015, Devon and its consolidated subsidiaries had approximately 6,600 employees. Approximately 1,400 of such 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, http://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 (including our Code of Ethics for the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer). 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.

Strategy

Our primary goal is to build value per debt-adjusted share by:

- exploring for undiscovered oil and natural gas reserves;
- purchasing and developing oil and natural gas properties;
- enhancing the value of production through marketing and midstream activities;
- optimizing production operations to control costs; and
- maintaining a strong balance sheet.

During 2015, we continued to execute on this strategy and experienced a number of key achievements that are outlined in this report. However, we, and the entire upstream energy sector, have faced both operational and financial challenges as oil and natural gas prices weakened significantly throughout 2015 and continued into 2016. To navigate these turbulent times, we are using our focused strategy, flexible portfolio of assets and leadership experience to execute on a number of initiatives that will ensure our long-term financial strength.

Specifically, after completing the STACK acquisition discussed in this report, we had approximately $3.9 billion of liquidity.

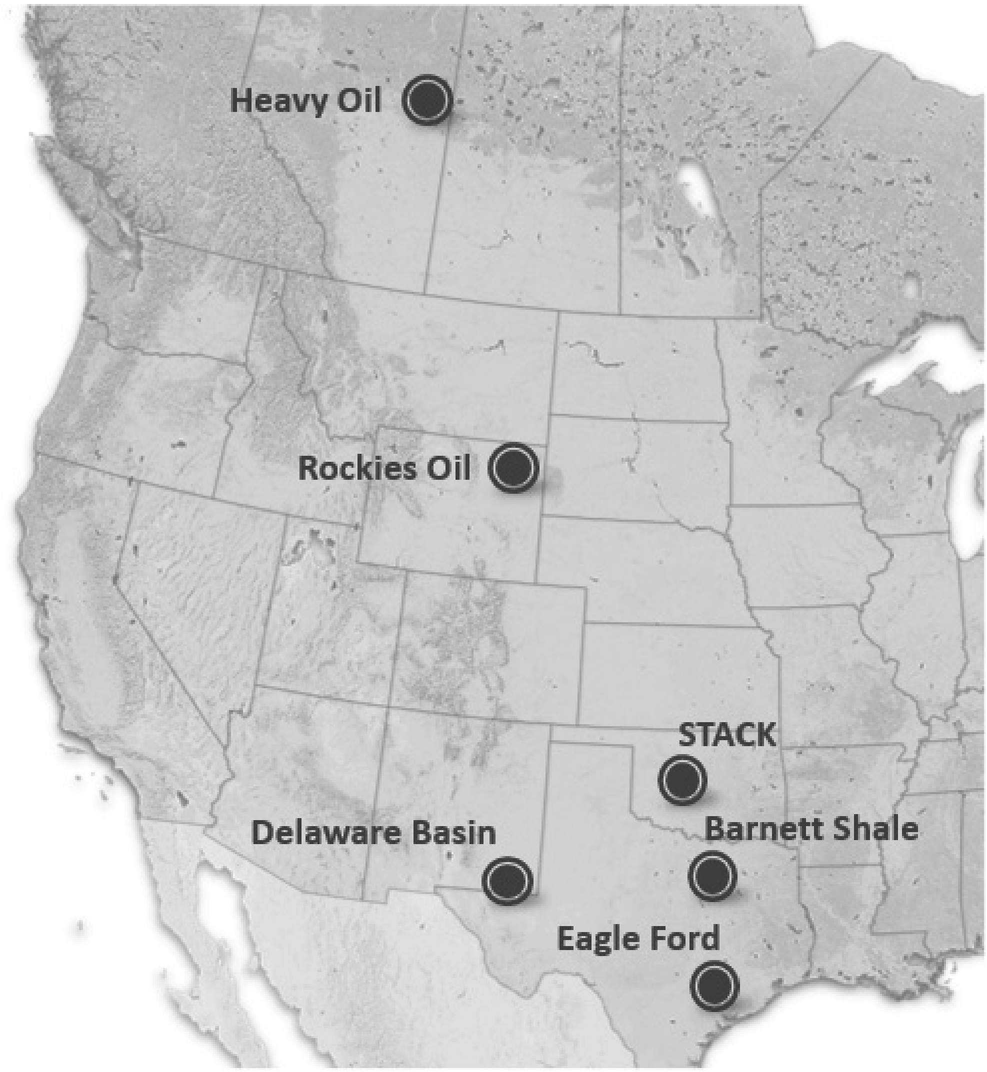
While we will continue to operate and develop our premier portfolio of assets, we are committed to protecting our balance sheet and managing our capital programs to be within our cash inflows, including Access Pipeline proceeds. As a result, we are significantly reducing our capital investment in response to lower commodity prices. We plan to invest $900 million to $1.1 billion in our upstream programs, a decrease of roughly 75% compared to our 2015 capital. We are also committed to reducing our G&A and field-level operating costs commensurate with our reduced, but focused, activity level. Following a number of cost-reduction initiatives culminating with our February 2016 workforce reduction, we are expecting a $700 million to $900 million reduction in operating and G&A costs on an annualized basis.

Also, in February 2016, we reduced our quarterly common stock dividend 75% to $0.06 per share.

Oil and Gas Properties

Property Profiles

The locations of our core oil and gas properties are presented on the following map. Additional information related to these properties follows this map, as well as information describing EnLink's assets.



The following table outlines a summary of key data in each of our operating areas as of and for the year ended December 31, 2015. Notes 20 and 21 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
Delaware Basin	123	6%	78%	61	9%	79%	167
STACK	264	12%	42%	64	9%	42%	130
Eagle Ford	103	4%	76%	115	17%	79%	275
Rockies Oil	28	1%	66%	23	3%	70%	65
Heavy Oil	544	25%	100%	115	17%	97%	79
Barnett Shale	841	39%	25%	182	27%	27%	5
Core assets	1,903	87%	55%	560	82%	61%	721
Other	279	13%	57%	120	18%	58%	129
Total	2,182	100%	56%	680	100%	60%	850

Delaware Basin – The Delaware Basin has been a legacy asset for Devon 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 potential for many years to come. In 2016, we plan to invest approximately $200 million of capital in the Delaware Basin, primarily focused on the second Bone Spring opportunity in the basin of southeast New Mexico.

STACK – In early January 2016, we increased our acreage in the Woodford Shale and Meramec plays by acquiring 80,000 net acres in the STACK. The STACK development, located primarily in Oklahoma's Canadian, Kingfisher and Blaine counties, is named for the stacked pay in the area. Our Woodford Shale position is the largest and one of the best in the industry. Recent well-completion design enhancements have resulted in greater productivity and improved economics. Early drilling activity in the Meramec play has been encouraging across our core position in the oil and liquids window. In 2016, we plan approximately $325 million of capital investment.

Eagle Ford – We acquired our position in the Eagle Ford in early 2014 from GeoSouthern and have approximately 66,000 net acres located in the DeWitt and Lavaca counties in south Texas. Since acquiring these assets, we have delivered tremendous results, increasing production by 125%. Our excellent results are driven by our development in DeWitt County which is located in the economic core of the play. In 2016, we expect our Eagle Ford assets to once again deliver the highest operating margin of any asset in the portfolio and plan approximately $200 million of capital investment.

Rockies Oil – Our operations are focused on emerging oil opportunities in the Powder River Basin and the Wind River Basin. In the Powder River, we are currently targeting several Cretaceous oil objectives, including the Turner, Parkman and Frontier formations. 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. In December 2015, we acquired 253,000 net acres in the "core" of the oil fairway in the Powder River. This acquisition delivers some of the best returns in our portfolio and is a significant resource opportunity. In 2016, we plan approximately $75 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, a 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. In 2014, we brought the third phase of Jackfish into operation, which ramped up to facility capacity by the third quarter of 2015. We expect each phase to maintain a reasonably flat production profile for greater than 20 years at an average gross production rate of approximately 35 MBbls per day at each facility.

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, 2015. With our 50% partner, we are evaluating our development timeline for Pike.

To facilitate the delivery of our heavy oil production, we have a 50% interest in the Access Pipeline transportation system in Canada. This pipeline system allows us to blend our heavy oil production with condensate or other blend-stock and transport the combined product to the Edmonton area for sale. The Access Pipeline system has the capacity to transport approximately 170 MBbls of bitumen blend per day, net to our 50% interest. As discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of this report, we have plans to monetize our interest in Access Pipeline in 2016. With any buyer of Access Pipeline, we will also enter into a contractual arrangement to continue transporting our heavy oil volumes on Access Pipeline.

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 2016, we plan approximately $175 million of capital investment in our Canadian Heavy Oil business.

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 into one of the top producing gas fields in North America. Given the commodity price environment in 2015, we shifted focus to enhancing existing well performance through re-fracturing, artificial lift and line pressure reduction projects. In 2015, we accelerated our horizontal refrac program to test the re-stimulation of 25 wells and also had an active vertical refrac program, re-stimulating 140 vertical wells. In 2016, we plan on minimal refrac activity in the Barnett.

Other – Other assets are located primarily in the Midland Basin, east Texas, Granite Wash and Mississippian-Lime areas. Substantially all of these properties have been identified for divestiture in 2016.

Proved Reserves

For estimates of our proved developed and proved undeveloped reserves and the discussion of the contribution by each key property, see Note 21 in "Item 8. Financial Statements and Supplementary Data" of this report.

Since the beginning of 2015, no estimates of our proved reserves have been filed with or included in reports to any federal or foreign governmental authority or agency except in filings with the SEC and the DOE. Reserve estimates filed with the SEC correspond with the estimates of our reserves contained in this report. Reserve estimates filed with the DOE are based upon the same underlying technical and economic assumptions as the estimates of our reserves included in this report. However, the DOE requires reports to include the interests of all owners in wells that we operate and to exclude all interests in wells that we do not operate.

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 ("Qualified 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 Group's Director and key members of the Group have appropriate technical qualifications to oversee the preparation of reserves estimates, including any or all of the following:

- an undergraduate degree in petroleum engineering from an accredited university, or equivalent;
- a petroleum engineering license, or similar certification;
- memberships in oil and gas industry or trade groups; and
- relevant experience estimating reserves.

The current Director of the Group has all of the qualifications listed above. The current Director has been involved with reserves estimation in accordance with SEC definitions and guidance since 1987. He has 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. He has been employed by Devon for the past fifteen years, including the past eight in his current position. During his career, he has been responsible for reserves estimation as the primary reservoir engineer for projects including, but not limited to:

- Hugoton Gas Field (Kansas);
- Sho-Vel-Tum CO_2 Flood (Oklahoma);
- West Loco Hills Unit Waterflood and CO_2 Flood (New Mexico);
- Dagger Draw Oil Field (New Mexico);
- Clarke Lake Gas Field (Alberta, Canada);
- Panyu 4-2 and 5-1 Joint Development (Offshore South China Sea); and
- ACG Unit (Caspian Sea).

From 2003 to 2010, he served as the reservoir engineering representative on our internal peer review team. In this role, he reviewed reserves and resource estimates for projects including, but not limited to, the Mobile Bay Norphlet Discoveries (Gulf of Mexico Shelf), Cascade Lower Tertiary Development (Gulf of Mexico Deepwater) and Polvo Development (Campos Basin, Brazil).

The Group reports independently of any of our operating divisions and currently is in our Chief Financial Officer's organization. No portion of the Group's compensation is directly dependent on the quantity of reserves booked.

Throughout the year, the Group performs internal reserves audits of each operating division's reserves. Selection criteria of reserves that are audited include major fields and major additions and revisions to reserves. In addition, the Group reviews reserve estimates with each of the third-party petroleum consultants discussed below. The Group also ensures our Qualified Estimators obtain continuing education related to the fundamentals of SEC proved reserves assignments.

The Group also oversees audits and reserves estimates performed by third-party petroleum consulting firms. During 2015, we engaged two such firms to audit 95% of our proved reserves. LaRoche Petroleum Consultants, Ltd. audited 94% of our 2015 U.S. reserves, and Deloitte LLP audited 96% of our Canadian reserves.

“Audited” reserves are those quantities of reserves that were estimated by our employees and audited by an independent petroleum consultant. The Society of Petroleum Engineers’ definition of an audit is an examination of a company’s proved oil and gas reserves and net cash flow by an independent petroleum consultant that is conducted for the purpose of expressing an opinion as to whether such estimates, in aggregate, are reasonable and have been estimated and presented in conformity with generally accepted petroleum engineering and evaluation methods and procedures.

In addition to conducting these internal and external 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 Reserves Committee assists the Board of Directors with its duties and responsibilities in evaluating and reporting our proved reserves, much like our Audit Committee assists the Board of Directors in supervising our audit and financial reporting requirements. Besides being independent, 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 responsibilities of the Reserves Committee include the following:

- approve the scope of and oversee an annual review and evaluation of our oil, gas and NGL reserves;
- oversee the integrity of our reserves evaluation and reporting system;
- oversee and evaluate our compliance with legal and regulatory requirements related to our reserves;
- review the qualifications and independence of our third-party petroleum consultants; and
- monitor the performance of our third-party petroleum consultants.

The following table presents our estimated pre-tax cash flow information related to our proved reserves. These estimates correspond with the method used in presenting the “Supplemental Information on Oil and Gas Operations” in Note 21 to our consolidated financial statements included in this report.

	Year Ended December 31, 2015		
	U.S.	Canada	Total
		(Millions)	
Pre-Tax Future Net Revenue (Non-GAAP) (1)			
Proved Developed Reserves	$6,382	$1,874	$ 8,256
Proved Undeveloped Reserves	459	1,523	1,982
Total Proved Reserves	$6,841	$3,397	$10,238
Pre-Tax 10% Present Value (Non-GAAP) (1)			
Proved Developed Reserves	$4,609	$1,657	$ 6,266
Proved Undeveloped Reserves	259	458	717
Total Proved Reserves	$4,868	$2,115	$ 6,983

(1) Estimated pre-tax future net revenue represents estimated future revenue to be generated from the production of proved reserves, net of estimated production and development costs and site restoration and abandonment charges. The amounts shown do not give effect to DD&A, asset impairments or non-property related expenses such as debt service and income tax expense.

Pre-tax future net revenue and pre-tax 10% present value are non-GAAP measures. The standardized measure was $6.7 billion at the end of 2015. Included as part of the standardized measure were discounted future income taxes of $0.3 billion. Excluding these taxes, the pre-tax 10% present value was $7.0 billion. We believe the pre-tax 10% present value is a useful measure in addition to the after-tax standardized measure. The pre-tax 10% present value assists in both the estimation of future cash flows of the current reserves as well as in making relative value comparisons among peer companies. The after-tax standardized measure is dependent on the unique tax situation of each individual company, while the pre-tax 10% present value is based on prices and discount factors, which are more consistent from company to company.

Production, Production Prices and Production Costs

The following table presents 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)**
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.	47	—	660	50	207
Canada	10	20	41	1	39
Total North America	57	20	701	51	246
2013					
Barnett Shale	1	—	374	20	83
Jackfish	—	19	—	—	19
U.S.	28	—	709	41	189
Canada	15	19	165	4	64
Total North America	43	19	874	45	253

	Average Sales Price				
Year Ended December 31,	**Oil (Per Bbl)**	**Bitumen (Per Bbl)**	**Gas (Per Mcf)**	**NGLs (Per Bbl)**	**Production Cost (Per Boe) (1)**
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	$0.67	$ —	$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
2013					
Barnett Shale	$97.74	$ —	$2.90	$22.45	$ 4.12
Jackfish	$ —	$48.04	$ —	$ —	$17.98
U.S.	$94.52	$ —	$3.10	$25.75	$ 6.65
Canada	$69.18	$48.04	$3.05	$46.17	$15.78
Total North America	$86.02	$48.04	$3.09	$27.33	$ 8.97

(1) Represents LOE per Boe and excludes severance and property taxes.

Drilling Statistics

The following table summarizes our development and exploratory drilling results.

Year Ended December 31,	Development Wells (1)		Exploratory Wells (1)		Total Wells (1)		
	Productive	Dry	Productive	Dry	Productive	Dry	Total
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
2013							
U.S.	555.3	—	56.1	7.0	611.4	7.0	618.4
Canada	211.9	1.0	7.4	—	219.3	1.0	220.3
Total North America	767.2	1.0	63.5	7.0	830.7	8.0	838.7

(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, 2015. As of February 1, 2016, these wells were still in progress.

	Gross (1)	Net (2)
U.S.	17.0	8.6
Canada	—	—
Total North America	17.0	8.6

(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, 2015.

	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.	10,895	4,352	15,130	10,313	26,025	14,665
Canada	3,264	3,166	698	498	3,962	3,664
Total North America	14,159	7,518	15,828	10,811	29,987	18,329

(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 809 and 1,565 oil and gas wells, respectively, which had multiple completions and were operated by Devon.

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 19,000 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, 2015. Of our 5.5 million net acres, approximately 3.0 million acres are held by production. The acreage in the table includes 0.2 million, 0.4 million and 0.1 million net acres subject to leases that are scheduled to expire during 2016, 2017 and 2018, respectively. As of December 31, 2015, there were no proved undeveloped reserves associated with our expiring acreage. Of the 0.7 million net acres set to expire by December 31, 2018, 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 2015, we allowed approximately 0.8 million acres to expire.

	Developed		Undeveloped		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
			(Thousands)			
U.S.	2,598	1,732	4,654	2,207	7,252	3,939
Canada	705	520	2,147	1,026	2,852	1,546
Total North America	3,303	2,252	6,801	3,233	10,104	5,485

(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. Investigations, which generally include a title opinion 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 Properties

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 1.3 Bcf/d, processing facilities with a total processing capacity of approximately 1.4 Bcf/d and gathering systems with total capacity of approximately 2.9 Bcf/d.
- *Oklahoma* – The Oklahoma assets consist of processing facilities with a total processing capacity of approximately 550 MMcf/d and gathering systems with total capacity of approximately 605 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 1.7 Bcf/d, gathering

systems with total capacity of approximately 510 MMcf/d, 660 miles of liquids transport lines and four fractionation assets with total fractionation capacity of 198 MBbls/d.

- *Crude and Condensate* – The Crude and Condensate assets consist of approximately 350 miles of crude oil and condensate pipelines with total capacity of approximately 101 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 and Midstream Activities

Midstream Operations

Comprising approximately 98% of our 2015 midstream operating profit, EnLink is the primary component of our midstream operations. EnLink's operations primarily focus on providing midstream energy services, which consist of gathering, transmission, processing, fractionation and marketing, to producers of natural gas, NGLs, crude oil and condensate, 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.

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 periodically 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 2016, our production was sold under the following contract terms.

	Short-Term		Long-Term	
	Variable	Fixed	Variable	Fixed
Oil and bitumen	72%	—	28%	—
Natural gas	36%	4%	60%	—
NGLs	52%	10%	38%	—

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, 2015, we were committed to deliver the following fixed quantities of production.

	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Oil and bitumen (MMBbls)	145	38	56	46	5
Natural gas (Bcf)	736	439	287	10	—
NGLs (MMBbls)	12	12	—	—	—
Total (MMBoe)	280	123	104	48	5

We expect to fulfill our delivery commitments primarily with production from our proved developed reserves. In certain regions, such as in our Heavy Oil operation in Canada, we expect to fulfill these longer-term delivery commitments with our proved undeveloped reserves.

Generally, our proved reserves have 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 may be subject to deficiency payments. In such instances, we can and may use spot market purchases to satisfy the commitments.

Customers

During 2015, 2014 and 2013, no purchaser accounted for over 10% of our consolidated operating revenues.

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, state conservation laws generally limit the venting or flaring of natural gas and 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 by the federal government and administered by the Bureau of Land Management 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. 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 and royalty payment obligations for production from federal lands.

Royalties and Incentives in Canada

The royalty system in Canada is a significant factor in the profitability of Canadian oil and gas production. 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. The regulations prescribe lower royalty rates for oil sands projects until allowable capital costs have been recovered. Recently, the province of Alberta released the findings of the Royalty Review Advisory Panel, which concluded that the royalties for oil sands were appropriate and should be maintained in the new royalty system to be implemented in 2017.

Marketing in Canada

Any oil or gas export that exceeds a certain duration or a certain quantity requires an exporter to obtain export authorizations from Canada's National Energy Board. The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere.

Environmental 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 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; 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. 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 will likely 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.

Oil, Gas and NGL Prices Are Volatile

Our financial results 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. Since the second half of 2014, there has been a significant decline in oil, gas and NGL prices, which has adversely affected our 2015 operating results and contributed to a reduction in our anticipated future capital expenditures. In addition, this decline in commodity prices has adversely impacted our estimated proved reserves and resulted in substantial impairments to our oil and gas properties during 2015. 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 further 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.

Historically, market prices and our realized prices have been volatile and are likely to continue to be volatile in the future due to numerous factors beyond our control. These factors include, but are not limited to:

- supply of and demand for oil, gas and NGLs, including consumer demand in emerging markets, such as China;
- conservation and environmental protection efforts;
- OPEC production levels;
- geopolitical risks;
- 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;
- the overall economic environment; and
- governmental regulations and taxes.

Estimates of Oil, Gas and NGL Reserves Are Uncertain

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 estimates of future net revenue, as well as our financial condition 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;
- unexpected 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 resources used in drilling and completion operations; and
- shortages or delays in the availability of services or delivery of equipment.

A significant occurrence of one 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.

Hedging Limits Participation in Commodity Price Increases

We periodically 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.

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 and may not be able to meet their financial obligations to us, particularly if commodity prices remain depressed or decline further. Any such default by these counterparties could adversely impact our financial results.

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, health and safety, wildlife conservation, 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 and well operations. If permits are not issued, or if unfavorable restrictions or conditions are imposed on our drilling 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 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, enact 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, seismic activity, income taxes and climate change as discussed below.

Hydraulic Fracturing – The U.S. Environmental Protection Agency ("EPA") and other federal agencies, including the Bureau of Land Management ("BLM") have made proposals that, if implemented, could either restrict the practice of hydraulic fracturing or subject the process to further regulation. For example, the EPA has also issued final regulations under the federal Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing and proposed in April 2015 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. The BLM and many 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 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 are subject to stringent and complex regulations related to pipeline safety and integrity management. The Department of Transportation, through the Pipeline and Hazardous Materials Safety Administration ("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. 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 north-central Oklahoma and elsewhere have prompted concerns about seismic activity and possible relationships with the energy industry, specifically disposal wells used to inject, into the subsurface, water that is produced along with oil and natural gas. Legislative and regulatory initiatives intended to address these concerns may result in additional levels of regulation that could limit or eliminate our ability to inject produced water into certain disposal wells. Restrictions on such disposal wells could lead to operational delays, increase our operating and compliance costs or otherwise adversely affect our operations. In addition, we could be subject to third-party lawsuits seeking alleged property damages as a result of induced seismic activity in our areas of operation.

Income Taxes – 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. The U.S. President and other policy makers have proposed provisions that would, if enacted, make significant changes to U.S. tax laws applicable to us. One significant proposal that has recently been considered at the federal level would eliminate the immediate deduction for intangible drilling and development costs. The adoption of this proposal or other tax changes could have a material adverse effect on our profitability, financial condition and liquidity.

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 that are 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 proposed 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 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. Severe limitations on greenhouse gas emissions could also adversely affect demand for oil and natural gas, which could have a material adverse effect our profitability, financial condition and liquidity.

Currently, the Alberta Government is developing a new strategy on climate change based on recommendations put forward by the Climate Change Advisory Panel. It is expected that these recommendations will create additional costs for the Canadian 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 Debt May Limit Our Liquidity and Financial Flexibility, and Any Downgrade of Our Credit Rating Could Adversely Impact Us

As of December 31, 2015, we had total consolidated indebtedness of $13.1 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. A ratings downgrade could adversely impact our ability to access financing and trade credit and increase our interest rate under any credit facility borrowing as well as the cost of any other future debt. A ratings downgrade to a rating below investment-grade made by one or more rating agencies could potentially require us to post collateral under certain contractual arrangements.

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.

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, then 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, the current commodity price environment may result in fewer potential bidders, unsuccessful sales efforts and a higher risk that buyers may seek to terminate a transaction prior to closing. In addition, we may not realize any expected cost savings from asset dispositions, in part because of revenue losses from the divested properties.

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, natural 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. Additionally, for our non-operated properties, we generally depend on the operator for operational safety and regulatory compliance.

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, war and terrorism. 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.

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 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 natural gas production and to transport our oil, natural 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 from 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.

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. 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. 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.

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 might 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.

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

Not applicable.

Item 3. ***Legal Proceedings***

We are involved in various routine 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.

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 10, 2016, there were 8,307 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 2015 and 2014, as well as the quarterly dividends per share paid during 2015 and 2014.

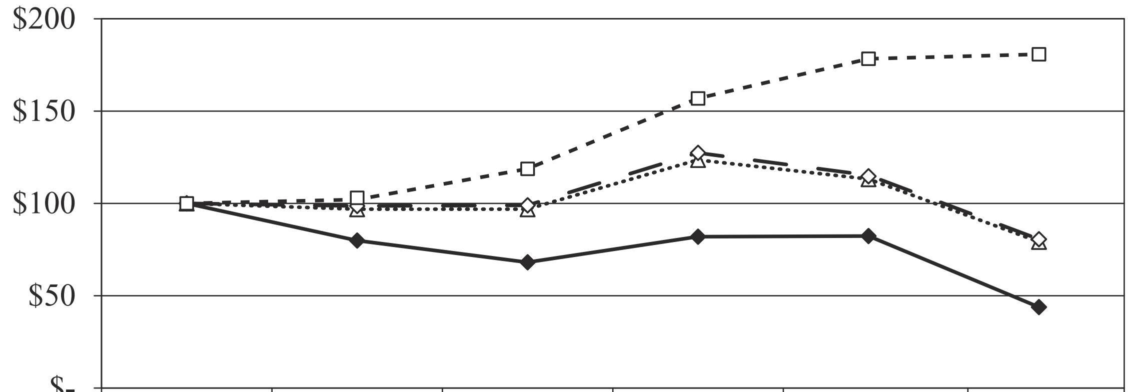
	Price Range of Common Stock		Dividends
	High	Low	Per Share
Quarter Ended 2015:			
December 31, 2015	$48.68	$28.00	$0.24
September 30, 2015	$59.80	$36.01	$0.24
June 30, 2015	$70.48	$58.77	$0.24
March 31, 2015	$67.08	$56.35	$0.24
Quarter Ended 2014:			
December 31, 2014	$68.80	$51.76	$0.24
September 30, 2014	$80.01	$67.58	$0.24
June 30, 2014	$80.63	$66.75	$0.24
March 31, 2014	$66.95	$57.67	$0.22

In February 2016, we reduced our quarterly common stock dividend 75% to $0.06 per share.

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, our new peer group and our old peer group of companies. Our new peer group includes Anadarko Petroleum Corporation, Apache Corporation, Chesapeake Energy Corporation, Concho Resources, Inc., Continental Resources, Inc., ConocoPhillips, Encana Corporation, EOG Resources, Inc., Hess Corporation, Marathon Oil Corporation, Murphy Oil Corporation, Noble Energy, Inc., Occidental Petroleum Corporation and Pioneer Natural Resources Company. Concho Resources, Inc. and Continental Resources, Inc. replaced Newfield Exploration Company and Talisman Energy, Inc. from our old peer group. The graph was prepared assuming $100 was invested on December 31, 2010 in Devon's common stock, the S&P 500 Index and the peer groups, and dividends have been reinvested subsequent to the initial investment.

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



	2010	2011	2012	2013	2014	2015
Devon	$100.00	$79.71	$67.80	$81.83	$82.13	$43.86
S&P 500	$100.00	$102.11	$118.45	$156.82	$178.29	$180.75
New Peer Group	$100.00	$98.47	$98.66	$127.29	$115.16	$80.44
Old Peer Group	$100.00	$96.89	$96.75	$123.42	$113.12	$79.21

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 2015.

Period	Total Number of Shares Purchased [1]	Average Price Paid per Share
October 1 – October 31	5,404	$41.78
November 1 – November 30	128,025	$45.99
December 1 – December 31	113,085	$44.94
Total	246,514	$45.41

(1) Share repurchases represent shares received by us from employees and directors 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 71,500 shares of our common stock in 2015, 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 2015, 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,				
	2015	2014	2013	2012	2011
	(Millions, except per share amounts)				
Operating revenues	$ 13,145	$19,566	$10,397	$ 9,501	$11,445
Earnings (loss) from continuing operations [1]	$(15,203)	$ 1,691	$ (20)	$ (185)	$ 2,134
Earnings (loss) from continuing operations attributable to Devon	$(14,454)	$ 1,607	$ (20)	$ (185)	$ 2,134
Earnings (loss) from continuing operations per share attributable to Devon – Basic	$ (35.55)	$ 3.93	$ (0.06)	$ (0.47)	$ 5.12
Earnings (loss) from continuing operations per share attributable to Devon – Diluted	$ (35.55)	$ 3.91	$ (0.06)	$ (0.47)	$ 5.10
Cash dividends per common share	$ 0.96	$ 0.94	$ 0.86	$ 0.80	$ 0.67
Weighted average common shares outstanding – Basic	412	409	406	404	417
Weighted average common shares outstanding – Diluted	412	411	406	404	418
Total assets [1]	$ 29,532	$50,637	$42,877	$43,326	$41,117
Long-term debt [2]	$ 12,137	$ 9,830	$ 7,956	$ 8,455	$ 5,969
Stockholders’ equity	$ 10,989	$26,341	$20,499	$21,278	$21,430

(1) During 2015, we recorded noncash asset impairments totaling $20.8 billion. During 2014, 2013 and 2012, we recorded noncash asset impairments totaling $2.0 billion in each year.
(2) Debt balances at December 31, 2015 and 2014 include $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*

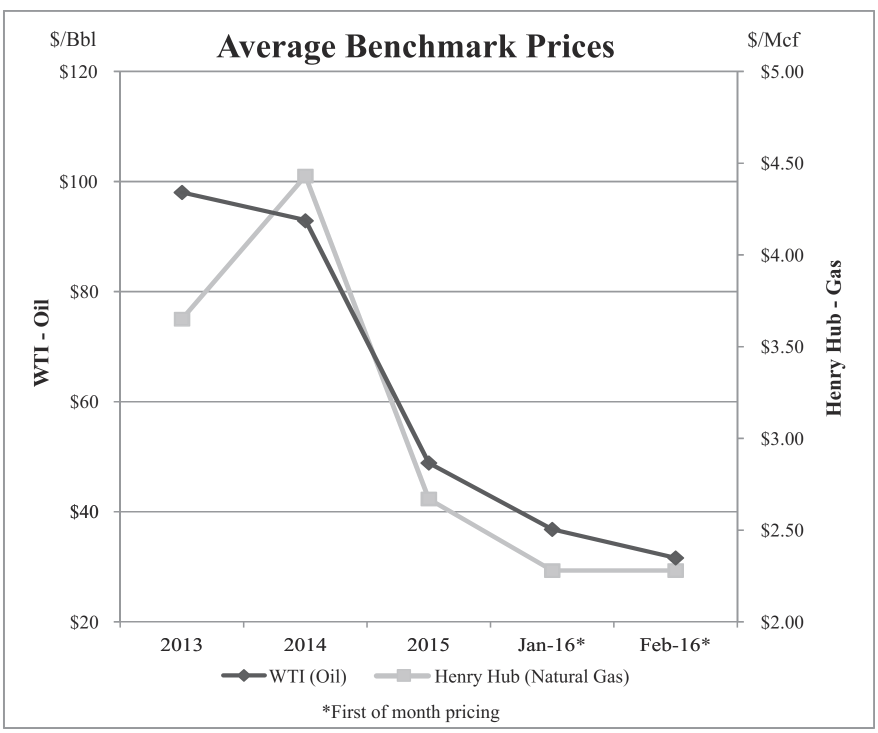
Introduction

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 2015 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. During 2015, we had several key operating and financial achievements:

- Delivered record crude oil and bitumen production, representing 41% of our total production
- Grew U.S. oil production 28% compared to 2014
- Achieved top-quartile well results in the Delaware Basin of southeast New Mexico
- Exceeded 35 MBbls per day nameplate capacity at Jackfish 3
- Expanded and improved our positions in the STACK and Powder River Basin areas with two separate acquisitions completed for approximately $2 billion of cash and common equity in late 2015 and early 2016
- Sold EnLink units and dropped our interest in VEX to EnLink, generating $821 million in total cash inflows to Devon
- Realized $2.4 billion in cash settlements on our commodity hedge positions
- Reduced LOE $228 million, or 10%, primarily through cost reduction initiatives
- Exited 2015 with $4.7 billion of liquidity consisting of $2.3 billion of cash and $2.4 billion of capacity on our Senior Credit Facility. We have managed our debt maturity schedule to provide maximum flexibility with near-term liquidity; we have no major long-term debt maturities until December 2018.



In spite of these and other operating achievements, weak commodity prices made 2015 a challenging year for the upstream energy sector, including us. As presented in the graph at left, the significant decline in crude oil prices that began in the third quarter of 2014 continued throughout 2015 and weakened further during the first two months of 2016. The 2015 WTI crude oil index was approximately 50% lower than the 2014 average. The downward pressure on oil prices has largely resulted from increased global supply, from both OPEC and non-OPEC countries, and a global economic slowdown that has decreased demand for oil. Similarly, the Henry Hub natural gas and OPIS Mont Belvieu, Texas indices decreased significantly since the end of 2014 as a result of an imbalance between supply and demand across North America.

As a result of these large commodity price declines and in spite of our operating achievements, we recognized $21 billion of noncash asset impairments throughout 2015 that have negatively impacted our financial earnings and retained earnings. Additionally, our core earnings, core earnings per share and operating cash flow for 2015 decreased significantly compared to 2014. Key measures of our financial performance in 2015 are summarized in the following table:

	Year Ended December 31,				
	2015	Change	2014	Change	2013
	(Millions, except per share and per Boe amounts)				
Net earnings (loss) attributable to Devon	$(14,454)	N/M	$ 1,607	N/M	$ (20)
Core earnings attributable to Devon (1)	$ 1,044	-48%	$ 2,017	+16%	$1,734
Earnings (loss) per share attributable to Devon	$ (35.55)	N/M	$ 3.91	N/M	$ (0.06)
Core earnings per share attributable to Devon (1)	$ 2.52	-49%	$ 4.91	+15%	$ 4.26
Core production (MBoe/d) (2)	560	+15%	489	+16%	423
Total production (MBoe/d)	680	+1%	673	-3%	693
Realized price per Boe (3)	$ 21.68	-46%	$ 40.33	+20%	$33.70
Operating cash flow	$ 5,383	-10%	$ 5,981	+10%	$5,436
Capitalized costs, including acquisitions	$ 6,233	-54%	$13,559	+104%	$6,643
Shareholder and noncontrolling interests distributions	$ 650	+5%	$ 621	+78%	$ 348
Reserves (MMBoe)	2,182	-21%	2,754	-7%	2,963

(1) Core earnings and core earnings per share attributable to Devon are financial measures not prepared in accordance with accounting principles generally accepted in the U.S. ("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) Core production is comprised of production in our key operating areas as outlined and discussed in "Items 1 and 2. Business and Properties" of this report.
(3) Excludes any impact of oil, gas and NGL derivatives.

Business and Industry Outlook

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. However, current market fundamentals indicate prices for crude oil and natural gas will continue to be depressed for much of 2016. Although changes in OPEC production strategies, macro-economic forecasts, geopolitical risks or other factors could impact current forecasts, we anticipate weak oil and natural gas prices throughout the majority of 2016.

In 2015, Devon marked its 44th anniversary in the oil and gas business and its 27th year as a public company. As an established company with a strong leadership team, we have experience operating in periods of weak commodity prices. With our focused strategy and portfolio of quality assets, we are prepared to successfully navigate the current pricing challenges and ensure our long-term financial strength.

Specifically, after completing the STACK acquisition, we began 2016 with approximately $3.9 billion of liquidity, consisting of cash and borrowing capacity under our credit facility. We expect to bolster this liquidity in 2016 by monetizing our interest in Access Pipeline and other non-core upstream assets for targeted total proceeds of $2 billion to $3 billion.

While we will continue to operate and develop our premier portfolio of assets, we are committed to protecting our balance sheet and managing our capital programs to be within our cash inflows, including Access Pipeline proceeds. As a result, we are significantly reducing our capital investment in response to lower commodity prices. We plan to invest $900 million to $1.1 billion in our upstream programs, a decrease of roughly 75% compared to our 2015 capital.

We are also committed to reducing our G&A and field-level operating costs commensurate with our reduced, but focused, activity level. In the first quarter of 2016, we announced plans to significantly reduce our workforce and other G&A costs to better align with the activity level of our core business in the current commodity price environment. The reductions are expected to decrease gross G&A costs by approximately $400 million to $500 million on an annualized basis, excluding associated employee severance and other restructuring costs. Following a number of cost-reduction initiatives culminating with our February 2016 workforce reduction, we are expecting a $700 million to $900 million reduction in operating and G&A costs on an annualized basis.

We estimate we will incur approximately $225 million to $275 million of restructuring costs as a result of the workforce reduction. We expect to recognize the majority of these restructuring costs in the first quarter of 2016 and will recognize the remaining costs throughout 2016 until our planned divestiture transactions have closed and further workforce reductions occur.

Also, in February 2016, we reduced our quarterly common stock dividend 75% to $0.06 per share.

Results of Operations

Oil, Gas and NGL Production

	Year Ended December 31,				
	2015	Change	2014	Change	2013
Oil (MBbls/d)					
Delaware Basin	39	+48%	26	+33%	20
STACK	6	+6%	6	+23%	5
Eagle Ford	66	+66%	39	N/M	—
Rockies Oil	15	+39%	10	-1%	11
Heavy Oil	27	+3%	26	-7%	28
Barnett Shale	1	-38%	2	-2%	2
Core assets	154	+42%	109	+66%	66
Other (1)	37	-25%	49	-5%	51
Total	191	+20%	158	+36%	117
Bitumen (MBbls/d)					
Heavy Oil	84	+51%	56	+8%	51
Gas (MMcf/d)					
Delaware Basin	73	+9%	67	+16%	57
STACK	226	-3%	234	+14%	205
Eagle Ford	148	+70%	87	N/M	—
Rockies Oil	40	-17%	47	-22%	61
Heavy Oil	22	-5%	23	-19%	28
Barnett Shale	797	-12%	909	-11%	1,025
Core assets	1,306	-4%	1,367	-1%	1,376
Other (1)	304	-45%	553	-46%	1,017
Total	1,610	-16%	1,920	-20%	2,393
NGLs (MBbls/d)					
Delaware Basin	9	+24%	8	+24%	6
STACK	21	-8%	22	+33%	17
Eagle Ford	25	+115%	11	N/M	—
Rockies Oil	1	+33%	1	+27%	1
Barnett Shale	48	-12%	55	-1%	55
Core assets	104	+7%	97	+23%	79
Other (1)	32	-25%	42	-11%	47
Total	136	-2%	139	+10%	126
Combined (MBoe/d)					
Delaware Basin	61	+35%	45	+27%	36
STACK	64	-4%	67	+21%	56
Eagle Ford	115	+75%	65	N/M	—
Rockies Oil	23	+29%	18	-6%	19
Heavy Oil	115	+34%	86	+2%	85
Barnett Shale	182	-13%	208	-9%	228
Core assets	560	+14%	489	+15%	424
Other (1)	120	-35%	184	-32%	269
Total	680	+1%	673	-3%	693

(1) Other assets are located primarily in the Midland Basin, east Texas, Granite Wash and Mississippian-Lime areas. Substantially all of these properties have been identified for divestiture in 2016.

Oil, Gas and NGL Pricing

	Year Ended December 31,				
	2015 (1)	Change	2014 (1)	Change	2013 (1)
Oil (per Bbl)					
U.S.	$44.01	-49%	$85.64	-9%	$94.52
Canada	$30.58	-55%	$68.14	-1%	$69.18
Total	$42.12	-49%	$82.47	-4%	$86.02
Bitumen (per Bbl)					
Canada	$23.41	-58%	$55.88	+16%	$48.04
Gas (per Mcf)					
U.S.	$ 2.17	-45%	$ 3.92	+27%	$ 3.10
Canada (2)	$ 0.67	-82%	$ 3.64	+19%	$ 3.05
Total	$ 2.14	-45%	$ 3.90	+26%	$ 3.09
NGLs (per Bbl)					
U.S.	$ 9.32	-62%	$24.46	-5%	$25.75
Canada	$ —	N/M	$50.52	+9%	$46.17
Total	$ 9.32	-63%	$24.89	-9%	$27.33
Combined (per Boe)					
U.S.	$21.12	-44%	$37.96	+20%	$31.59
Canada	$24.46	-54%	$53.11	+33%	$39.91
Total	$21.68	-46%	$40.33	+20%	$33.70

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

(2) The reported Canadian gas volumes include 12, 21 and 25 MMcf per day for the years ended 2015, 2014 and 2013, 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)		
2013 sales	$ 3,668	$ 902	$ 2,698	$1,254	$ 8,522
Change due to volumes	1,311	76	(533)	131	985
Change due to prices	(206)	160	572	(123)	403
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

Volumes 2015 vs. 2014 Oil, gas and NGL 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.

Volumes 2014 vs. 2013 Oil, gas and NGL sales increased due to volumes primarily because of a 66% increase in our core assets oil production. Such growth resulted from our Eagle Ford properties and the continued development of our properties in the Delaware Basin. In addition, we continued to grow our NGL production from the Delaware Basin and STACK, which resulted in $131 million of additional sales. Bitumen sales increased due to development of our Jackfish thermal heavy oil projects in Canada, including Jackfish 3 which had first sales in 2014. These increases were partially offset by a 20% decrease in our 2014 gas production, which was impacted by our asset divestitures and natural declines.

Prices 2015 vs. 2014 Oil, gas and NGL 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.

Prices 2014 vs. 2013 Oil, gas and NGL sales increased primarily because of a 20% increase in our realized prices without hedges. Our gas sales were the most significantly impacted. The change in our realized gas price was largely due to higher North American regional index prices upon which our gas sales are based. Additionally, our bitumen sales increased as a result of a 16% increase in our realized price, as a result of tighter bitumen and heavy oil differentials. These increases were partially offset by lower oil and NGL realized prices resulting from lower WTI crude oil index prices 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,		
	2015	2014	2013
		(Millions)	
Cash settlements:			
Oil derivatives	$ 2,083	$ 90	$ 55
Gas derivatives	333	(36)	139
NGL derivatives	—	1	1
Total cash settlements	2,416	55	195
Gains (losses) on fair value changes:			
Oil derivatives	(1,687)	1,721	(243)
Gas derivatives	(226)	213	(139)
NGL derivatives	—	—	(4)
Total gains (losses) on fair value changes	(1,913)	1,934	(386)
Oil, gas and NGL derivatives	$ 503	$1,989	$(191)

	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

	Year Ended December 31, 2013				
	Oil (Per Bbl)	Bitumen (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Boe (Per Boe)
Realized price without hedges	$86.02	$48.04	$3.09	$27.33	$33.70
Cash settlements of hedges	1.30	—	0.16	0.01	0.77
Realized price, including cash settlements	$87.32	$48.04	$3.25	$27.34	$34.47

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, basis swaps and call options. To facilitate a portion of our price swaps, we sold gas and oil call options for 2015 through 2016. The call options give counterparties the right to purchase production at a predetermined price.

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 generated net gains in 2015 and 2014 and incurred a net loss in 2013.

Marketing and Midstream Revenues and Operating Expenses

	Year Ended December 31,				
	2015	Change	2014	Change	2013
			(Millions)		
Operating revenues	$ 7,260	-5%	$ 7,667	+271%	$ 2,066
Product purchases	(6,028)	-8%	(6,540)	+382%	(1,356)
Operations and maintenance expenses	(392)	+43%	(275)	+40%	(197)
Operating profit	$ 840	-1%	$ 852	+66%	$ 513
Devon profit	$ 14	-84%	$ 88	-5%	$ 93
EnLink profit	826	+8%	764	+82%	420
Total profit	$ 840	-1%	$ 852	+66%	$ 513

2015 vs. 2014 Marketing and midstream operating profit changes were largely driven 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. The change was offset by a decrease in Devon's marketing activities due to a decrease in commodity prices.

2014 vs. 2013 Marketing and midstream operating profit largely increased as a result of higher prices and volumes, partially offset by higher operations and maintenance expenses. Of the $339 million increase, $344 million was attributed to EnLink's operations. Higher profits from EnLink's Texas segment, which includes the Bridgeport facility, and Louisiana segment were the largest drivers of the increase. The Louisiana segment operating profit increased because of acquisitions and completions of additional pipelines.

Devon's marketing activities were the primary driver of the increases in both operating revenues and product purchases. The higher marketing revenues and product purchases are primarily due to commitments we entered into to secure capacity on downstream oil pipelines. Marketing activities of EnLink also contributed to these increases.

Lease Operating Expenses

	Year Ended December 31,				
	2015	Change	2014	Change	2013
	(Millions, except per Boe amounts)				
LOE:					
U.S.	$1,551	-0%	$1,559	+24%	$1,257
Canada	553	-28%	773	-24%	1,011
Total	$2,104	-10%	$2,332	+3%	$2,268
LOE per Boe:					
U.S.	$ 7.52	+0%	$ 7.52	+13%	$ 6.65
Canada	$13.18	-34%	$20.10	+27%	$15.78
Total	$ 8.48	-11%	$ 9.49	+6%	$ 8.97

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.

2014 vs. 2013 Our absolute LOE changed largely as a result of our portfolio transformation initiatives, including our February 2014 purchase of Eagle Ford assets and our 2014 divestitures of non-core gas properties in the U.S. and Canada. Higher volumes from development of our Eagle Ford assets, as well as our Delaware Basin assets, caused U.S. LOE to increase. This increase was partially offset by the decrease resulting from the U.S. divestitures. The Canadian divestitures were the primary cause of the decrease in Canadian LOE.

Total LOE increased $0.52 per Boe primarily because of higher unit costs related to our Canadian operations. The higher Canadian unit costs largely resulted from the divestiture of the conventional natural gas assets in the second quarter of 2014 which resulted in lower total volumes while retaining the relatively higher-cost thermal heavy oil operations. Additionally, higher Jackfish royalties paid in 2014 also contributed to higher Canadian unit costs. The higher unit cost in the U.S. was primarily related to our liquids production growth, particularly in the Delaware Basin and Mississippian-Woodford Trend, where projects generate higher revenues but generally require a higher cost to produce per unit than our gas projects. Additionally, we experienced inflationary pressures on costs in certain operating areas, which also contributed to the higher LOE per Boe.

General and Administrative Expenses

	Year Ended December 31,				
	2015	Change	2014	Change	2013
	(Millions, except per Boe amounts)				
Gross G&A	$1,347	-2%	$1,369	+21%	$1,128
Capitalized G&A	(372)	-1%	(376)	+2%	(368)
Reimbursed G&A	(120)	-18%	(146)	+2%	(143)
Net G&A	$ 855	+1%	$ 847	+37%	$ 617
Net G&A per Boe	$ 3.45	+0%	$ 3.45	+41%	$ 2.44

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. These decreases were offset by an increase in EnLink G&A of approximately $40 million primarily resulting from a workforce increase associated with EnLink's 2015 acquisitions. Reimbursed G&A decreased subsequent to our 2014 asset divestitures.

2014 vs. 2013 Net G&A and net G&A per Boe increased largely due to higher employee compensation and benefits and $22 million of 2014 costs related to the EnLink and GeoSouthern transactions. The higher employee compensation and benefits costs were primarily related to share-based awards, which cause our G&A to be higher in the period in which our annual share-based grant is made. The grant related to our 2013 compensation cycle was made in the first quarter of 2014. The grant related to our 2012 compensation cycle was made in the fourth quarter of 2012. Additionally, the expansion of our workforce as a part of growing production operations at certain of our key areas also contributed to the increase.

Production and Property Taxes

	Year Ended December 31,				
	2015	Change	2014	Change	2013
			(Millions)		
Production	$198	-45%	$360	+31%	$275
Property and other	190	+8%	175	-6%	186
Production and property taxes	$388	-28%	$535	+16%	$461
Percentage of oil, gas and NGL sales:					
Production	3.7%	+1%	3.6%	+13%	3.2%
Property and other	3.5%	+100%	1.8%	-19%	2.2%
Total	7.2%	+33%	5.4%	-0%	5.4%

2015 vs. 2014 Our absolute 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. Property taxes as a percentage of oil, gas and NGL sales increased during 2015 primarily due to ad valorem and other taxes that do not change in direct correlation with oil, gas and NGL sales.

2014 vs. 2013 Production and property taxes increased primarily as a result of an increase in our U.S. revenues.

Depreciation, Depletion and Amortization

	Year Ended December 31,				
	2015	Change	2014	Change	2013
	(Millions, except per Boe amounts)				
DD&A:					
Oil and gas properties	$2,580	-11%	$2,896	+18%	$2,465
Other assets	549	+30%	423	+34%	315
Total	$3,129	-6%	$3,319	+19%	$2,780
DD&A per Boe:					
Oil and gas properties	$10.40	-12%	$11.79	+21%	$ 9.75
Other assets	2.21	+28%	1.72	+38%	1.24
Total	$12.61	-7%	$13.51	+23%	$10.99

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.

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. Other DD&A increased primarily due to EnLink’s acquisitions in 2014 and 2015.

2014 vs. 2013 DD&A from our oil and gas properties increased in 2014 largely because of higher DD&A rates. The higher rates resulted from our oil and gas drilling and development activities and the GeoSouthern acquisition, which were partially offset by the asset impairments recognized in 2013 and the 2014 asset divestitures. Other DD&A increased primarily due to the formation of EnLink in 2014.

Asset Impairments

During 2015, 2014 and 2013, we recognized asset impairments of $20.8 billion, $2.0 billion and $2.0 billion, respectively. For discussion on asset impairments, see Note 5 in “Item 8. Financial Statements and Supplementary Data” of this report.

Restructuring Costs

During 2015, 2014 and 2013, we recognized restructuring costs of $78 million, $46 million and $54 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.

Gains on Asset Sales

In conjunction with the divestiture of certain Canadian properties, we recognized gains of $1.1 billion in 2014. For further discussion, see Note 2 in “Item 8. Financial Statements and Supplementary Data” of this report.

Net Financing Costs

	Year Ended December 31,				
	2015	Change	2014	Change	2013
			(Millions)		
Interest based on debt outstanding	$565	+6%	$532	+14%	$466
Early retirement of debt	—	N/M	48	N/M	—
Capitalized interest	(62)	-11%	(70)	+26%	(56)
Other fees and expenses	20	-24%	26	-1%	27
Interest expense	523	-3%	536	+23%	437
Interest income	(6)	-41%	(10)	-49%	(20)
Net financing costs	$517	-2%	$526	+26%	$417

2015 vs. 2014 Net financing costs decreased during 2015 primarily as a result of the retirement premium and costs related to the early redemption of senior notes in 2014, which is further discussed in Note 13 in "Item 8. Financial Statements and Supplementary Data" of this report. Interest on outstanding borrowings increased during 2015 primarily due to an increase of $51 million in EnLink interest expense as a result of an increase in fixed-rate borrowings, partially offset by a $18 million decrease in Devon interest expense as a result of a decrease in its average fixed-rate borrowings.

2014 vs. 2013 Net financing costs increased primarily because of higher average borrowings resulting from the EnLink and GeoSouthern transactions and the 2014 early retirement premium and costs.

Income Taxes

	Year Ended December 31,		
	2015	2014	2013
Total income tax expense (benefit) (millions)	$(6,065)	$2,368	$169
Effective income tax rate	(29)%	58%	113%

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		
	2015	2014	2015	2014	2015	2014	2013 (1)
	(Millions)						
Operating cash flow	$ 4,756	$ 5,467	$ 627	$ 514	$ 5,383	$ 5,981	$ 5,436
Sale of subsidiary units	654	—	—	—	654	—	—
Divestitures of property and equipment	106	5,120	1	—	107	5,120	419
Capital expenditures	(4,735)	(6,192)	(573)	(796)	(5,308)	(6,988)	(6,502)
Acquisitions of property, equipment and businesses	(583)	(6,104)	(524)	(358)	(1,107)	(6,462)	(256)
Short-term investment activity, net	—	—	—	—	—	—	2,343
Debt activity, net	770	(2,789)	1,061	555	1,831	(2,234)	361
Shareholder and noncontrolling interests distributions	(396)	(486)	(254)	(135)	(650)	(621)	(348)
EnLink and General Partner distributions	268	158	(268)	(158)	—	—	—
EnLink dropdowns	167	—	(167)	—	—	—	—
Stock option proceeds	4	93	—	—	4	93	3
Issuance of subsidiary units	—	—	25	410	25	410	—
Effect of exchange rate and other	(131)	79	22	36	(109)	115	(27)
Net change in cash and cash equivalents	$ 880	$(4,654)	$ (50)	$ 68	$ 830	$(4,586)	$ 1,429
Cash and cash equivalents at end of period	$ 2,292	$ 1,412	$ 18	$ 68	$ 2,310	$ 1,480	$ 6,066

(1) 2013 amounts for EnLink consist of legacy Devon midstream assets.

Operating Cash Flow

Net cash provided by operating activities continued to be a significant source of capital and liquidity in 2015. 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.

Our operating cash flow increased 10% during 2014 primarily because of higher realized prices and liquids production growth, partially offset by higher expenses.

Excluding payments made for acquisitions, our consolidated operating cash flow funded 100% and approximately 86% of our capital expenditures during 2015 and 2014, respectively. In 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.

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 17 in “Item 8. Financial Statements and Supplementary Data” of this report.

Divestitures of Property and Equipment

During 2014, we completed our Canadian asset divestiture program and received proceeds of approximately $2.9 billion. Additionally, we completed the divestment of certain of our U.S. assets and received proceeds of approximately $2.2 billion.

During 2013, we sold our Thunder Creek operations in Wyoming for approximately $148 million and our Bear Paw Basin assets in Havre, Montana for approximately $73 million. We also sold other minor oil and gas assets.

Capital Expenditures

	Year Ended December 31,		
	2015	2014	2013
		(Millions)	
Oil and gas	$4,577	$5,735	$5,710
Midstream	56	348	455
Corporate and other	102	109	93
Devon capital expenditures	4,735	6,192	6,258
EnLink capital expenditures	573	796	244
Total capital expenditures	$5,308	$6,988	$6,502
Devon acquisitions	$ 583	$6,104	$ 256
EnLink acquisitions	524	358	—
Total acquisitions	$1,107	$6,462	$ 256

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 lower commodity prices, Devon's 2015 capital program was designed to be lower than 2014, particularly compared to the second half of 2014 when oil prices began to significantly decline. This change is evidenced by a 48% decrease in exploration and development costs from the fourth quarter of 2014 to the fourth quarter of 2015, as well as a 24% decrease in total capital expenditures from 2014 to 2015, excluding acquisitions. Excluding acquisitions, oil and gas capital spending was flat from 2013 to 2014, primarily due to utilization of the drilling carries in 2014 from our joint venture arrangements.

Capital expenditures for Devon's midstream operations are primarily for the construction and expansion of oil and gas gathering facilities and pipelines and are largely impacted by Devon's oil and gas drilling activities. Our 2014 and 2013 midstream capital expenditures largely related to the expansion of our Access Pipeline in Canada. The majority of our midstream capital is incurred by EnLink. EnLink's 2015 capital expenditures decreased compared to 2014 primarily as a result of pipeline construction and expansion projects that went into service in 2014. EnLink's 2013 capital expenditures primarily related to expansions of plants serving the Barnett Shale and Cana-Woodford Shale.

Acquisition capital spend in 2015 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 EnLink acquisition activity, see Note 2 in "Item 8. Financial Statements and Supplementary Data" of this report.

Short-Term Investment Activity, Net

During 2013, we purchased approximately $1.1 billion of short-term investments and redeemed approximately $3.4 billion. We consider securities with original contract maturities in excess of three months but less than one year to be short-term investments.

Debt Activity, Net

During 2015, our consolidated net debt borrowings 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 borrowings 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.

During 2013, we increased our debt borrowings by $361 million as a result of issuing $2.25 billion of debt related to the planned Eagle Ford acquisition and repaying approximately $1.9 billion of outstanding short-term debt.

Shareholder and Noncontrolling Interests Distributions

The following table summarizes our common stock dividends. The quarterly cash dividend was $0.20 per share in the first quarter of 2013. We increased the dividend rate to $0.22 per share in the second quarter of 2013 and to $0.24 per share in the second quarter of 2014.

	2015		2014		2013	
	Amount	Per Share	Amount	Per Share	Amount	Per Share
	(Millions, except per share amounts)					
Dividends	$ 396	$0.96	$386	$0.94	$348	$0.86

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 $254 and $135 million to non-Devon unitholders during 2015 and 2014, respectively.

EnLink and General Partner Distributions

Devon received $268 million and $158 million in distributions from EnLink and the General Partner during 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.

Stock Option Proceeds

We received $4 million, $93 million and $3 million from stock option proceeds in 2015, 2014 and 2013, respectively.

Issuance of Subsidiary Units

During 2015 and 2014, EnLink issued and sold approximately 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 $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.

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. Other 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. We estimate the combination of these sources of capital will continue to be adequate to fund future capital expenditures, 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 10% in 2015 as a result of the significant 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 divestiture proceeds and 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. We expect lower prices to continue throughout 2016, and currently, our production is largely unhedged. If commodity prices remain consistent with 2015 and we are unable to obtain favorable hedge contracts for our 2016 production, our 2016 operating cash flow could materially decline from what it was in 2015.

The key terms to our oil, gas and NGL derivative financial instruments as of December 31, 2015 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.

Divestitures of Property and Equipment – In the fourth quarter of 2015, we announced our intention to monetize up to 80 MBoe per day of certain non-core upstream assets across our portfolio in 2016. In addition, we also intend to market our Access Pipeline in Canada. We anticipate these divestitures will generate approximately $2 billion to $3 billion of proceeds to further strengthen our financial position in 2016.

Interest Rates – Our operating cash flow can also be impacted by interest rate fluctuations. As of December 31, 2015, we had total debt of $13.1 billion with an overall weighted-average borrowing rate of 4.9%. Of the $13.1 billion of total debt, $1.4 billion is comprised of floating rate debt instruments that bear interest rates averaging 1.1%.

Credit Losses – Our operating cash flow is also exposed to credit risk in a variety of ways. We are exposed to the credit risk of the customers who purchase our oil, gas and NGL production. We are also exposed to credit risk related to the collection of receivables from our joint-interest partners for their proportionate share of expenditures made on projects we operate. Additionally, we are exposed to the credit risk of 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 2016 exploration and development capital budget is expected to be approximately $900 million to $1.1 billion, or roughly 75% less than our 2015 capital program. With our 2016 capital focused primarily on oil development, we anticipate our oil production will remain relatively flat from 2015 to 2016, but our natural gas and NGL production will decline, resulting in a 6% production decline in our core assets.

At the end of 2015, we held approximately $2.3 billion of cash. Included in this total was $646 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 commercial paper program. Amounts borrowed under the Senior Credit Facility may, at our election, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. However, we may elect to borrow at the prime rate. As of December 31, 2015, there were no borrowings under the Senior Credit Facility.

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, 2015, we were in compliance with this covenant. Our debt-to-capitalization ratio at December 31, 2015, as calculated pursuant to the terms of the agreement, was 23.7%.

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.

Our Senior Credit Facility supports our $3.0 billion of short-term credit under our 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. As of December 31, 2015, we had $626 million of borrowings under our commercial paper program.

EnLink has a $1.5 billion unsecured revolving credit facility. The General Partner has a $250 million revolving credit facility. As of December 31, 2015, there were $11 million in outstanding letters of credit and $414 million borrowed under the $1.5 billion credit facility and no outstanding borrowings under the $250 million credit facility. All of EnLink’s and the General Partner’s debt is non-recourse to Devon.

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

Devon and EnLink are rated by the major debt ratings agencies in the U.S. However, the General Partner does not receive debt ratings. In determining those debt ratings, the agencies consider a number of qualitative and quantitative items including, but not limited to, commodity pricing levels, liquidity, asset quality, reserve mix, debt levels, cost structure, planned asset sales, near-term and long-term growth opportunities and capital allocation challenges.

There are no “rating triggers” in any of our or EnLink’s contractual debt obligations that would accelerate scheduled maturities should debt ratings fall below a specified level. However, a ratings downgrade 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

In January 2016, Devon acquired Anadarko Basin STACK assets for approximately $1.5 billion in cash and equity, subject to certain adjustments. Including this acquisition but excluding EnLink, our 2016 capital expenditures are expected to range from $1.2 billion to $1.4 billion, including $900 million to $1.1 billion for our oil and gas 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 2016 capital expenditures until later periods or accelerate capital expenditures planned for periods beyond 2016 to achieve the desired balance between sources and uses of liquidity. Based upon current price expectations for 2016, available cash balances and credit availability and proceeds from our divestiture program, we anticipate having adequate capital resources to fund our 2016 capital expenditures.

In connection with our acquisition of the STACK play and Powder River Basin assets, we issued 23,470,000 shares of our common stock (the “STACK Acquisition Shares”) and 6,857,488 shares of our common stock (the “PRB Acquisition Shares”), respectively. Pursuant to the terms of these acquisitions, we agreed to register for resale with the SEC the STACK Acquisition Shares and the PRB Acquisition Shares. Following such respective registrations, the STACK Acquisition Shares and the PRB Acquisition Shares can generally be freely sold in the public markets at any time on or after February 21, 2016 and March 16, 2016, respectively.

EnLink Capital Resources and Expenditures

In January 2016, EnLink acquired Tall Oak, a gathering and processing midstream company with assets in central Oklahoma, for approximately $1.5 billion in cash and equity, subject to certain adjustments.

Excluding this acquisition, EnLink's 2016 capital budget includes approximately $445 million to $570 million of identified growth projects. EnLink's primary capital projects for 2016 include completing the construction of the Riptide plant in Texas, acquired as part of the Coronado transaction, commencing construction on 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 2016 maintenance capital expenditures from operating cash flows. In 2016, 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, 2015.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			(Millions)		
Devon debt (1)	$10,051	$ 976	$ 875	$ 700	$ 7,500
EnLink debt (2)	3,077	—	—	814	2,263
Interest expense (3)	9,804	630	1,252	1,115	6,807
Purchase obligations (4)	3,905	557	1,494	1,648	206
Operational agreements (5)	4,601	994	1,908	657	1,042
Asset retirement obligations (6)	1,414	44	104	102	1,164
Drilling and facility obligations (7)	189	69	85	7	28
Lease obligations (8)	443	70	134	110	129
Other (9)	140	2	92	39	7
Total (10)	$33,624	$3,342	$5,944	$5,192	$19,146

(1) Debt amounts represent scheduled maturities of Devon's debt obligations at December 31, 2015, excluding $28 million of net discounts included in the carrying value of debt. Debt due less than one year includes $626 million of commercial paper, which can be renewed beyond one year.

(2) Debt amounts represent scheduled maturities of EnLink's debt obligations at December 31, 2015, excluding $13 million of net premiums included in the carrying value of debt. All of EnLink's debt is non-recourse to Devon.

(3) Interest expense represents the scheduled cash payments on long-term, fixed-rate debt and an estimate of our floating-rate notes. These amounts include $1.8 billion of interest expense related to EnLink.

(4) 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.

(5) 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. Operational agreements include approximately $1.7 billion of minimum volume commitments between Devon and EnLink. The initial terms of the gas volume contracts with EnLink are summarized in the following table. In addition, Devon and EnLink have a 30 MBbls/d minimum transportation volume commitment for the VEX pipeline. All contracts with EnLink expire in 2019.

Contract	Contract Terms (Years)	Minimum Gathering Volume Commitment (MMcf/d)	Minimum Processing Volume Commitment (MMcf/d)	Minimum Volume Commitment Term (Years)	Annual Rate Escalators
Bridgeport gathering and processing contract	10	850	650	5	CPI
East Johnson County gathering contract	10	125	—	5	CPI
Cana gathering and processing contract	10	330	330	5	CPI

(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, 2015 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) These amounts include $133 million related to uncertain tax positions.
(10) This table excludes approximately $1.7 billion of cash payments made on January 7, 2016 upon closing the STACK acquisition and EnLink's acquisition of Tall Oak. The table also excludes the $500 million of future cash installment payments required to be paid by EnLink within 24 months as part of the Tall Oak acquisition.

Contingencies and Legal Matters

For a detailed discussion of contingencies and legal matters, see Note 18 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 2015, 95% 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 3% 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 for the last nine months of 2015 and the short-term pricing outlook for the first quarter of 2016, we expect to recognize additional U.S. and Canadian full cost impairments in the first quarter of 2016. The estimated U.S. impairment would be material to our net earnings, but we believe it will not be as large as the $3.7 billion impairment we recognized in the fourth quarter of 2015. We also expect to recognize an impairment related to our Canadian oil and gas properties that will approximate the impairment recognized in the fourth quarter of 2015. While difficult to measure, we estimate that the first quarter 2016 impairments will approximate $3 billion in the aggregate. Our full cost impairments have no impact to our cash flow or liquidity.

Derivative Financial Instruments

We periodically 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, and our foreign exchange forward contracts are held with six 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 our October 31, 2015 impairment test, step one of our impairment analysis showed that the fair value of our U.S. reporting unit exceeded its carrying value.

Sustained weakness in the overall energy sector beginning in the fourth quarter of 2014 and continuing into 2015 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, as well as an update performed as of December 31. Based on the results of the impairment analysis, it was determined that the estimated fair value of EnLink's Crude and Condensate, Louisiana and Texas reporting units were less than their carrying amounts, primarily due to changes in assumptions related to commodity prices and discount rates. Through the analysis, goodwill impairments of $492 million, $787 million and $49 million for EnLink's Texas, Louisiana and Crude and Condensate reporting units, respectively, were recognized in 2015. Subsequent to the impairments, EnLink had $93 million and $704 million of goodwill allocated to the Crude and Condensate and Texas reporting units, respectively. The Louisiana reporting unit's goodwill was entirely written off. As of December 31, 2015, the fair value of EnLink's Texas reporting unit exceeded its carrying value by approximately 7%, and the carrying value of EnLink's Crude and Condensate reporting unit approximated its fair value.

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 2015, we had deferred tax assets that largely resulted from the full cost impairments recognized in the fourth quarter of 2015. As a result of our recent cumulative losses, we recorded a 100% valuation allowance against our U.S. deferred tax assets as of December 31, 2015.

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 2015 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 costs were incurred in each of the three year periods; however, these costs relate to different restructuring programs. 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 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), our divestiture programs and related gains on asset sales and restructuring costs, repatriation of proceeds to the U.S., loss on early retirement of debt and deferred income tax on the formation of the General Partner. Amounts excluded for 2013 relate to derivatives and financial instrument fair value changes, asset impairments, our divestiture programs and related repatriation of proceeds to the U.S. and restructuring costs. 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. 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,		
	2015	2014	2013
	(Millions, except per share amounts)		
Net earnings (loss) attributable to Devon (GAAP)	$(14,454)	$ 1,607	$ (20)
Adjustments (net of taxes and noncontrolling interests):			
Derivatives and other financial instruments	(206)	(1,262)	131
Cash settlements on derivatives and financial instruments	1,552	31	139
Noncash effect of derivatives and financial instruments	1,346	(1,231)	270
Asset impairments	13,100	1,948	1,353
Deferred tax asset valuation allowance	967	—	—
Gain on asset sales and repatriations	33	(421)	97
Investment in General Partner deferred income tax	—	48	—
Restructuring costs	52	35	34
Early retirement of debt	—	31	—
Core earnings attributable to Devon (non-GAAP)	$ 1,044	$ 2,017	$1,734
Earnings (loss) per share attributable to Devon (GAAP)	$ (35.55)	$ 3.91	$ (0.06)
Adjustments (net of taxes and noncontrolling interests):			
Derivatives and other financial instruments	(0.49)	(3.07)	0.31
Cash settlements on derivatives and financial instruments	3.80	0.08	0.34
Noncash effect of derivatives and financial instruments	3.31	(2.99)	0.65
Asset impairments	32.18	4.74	3.35
Deferred tax asset valuation allowance	2.37	—	—
Gain on asset sales and repatriations	0.08	(1.02)	0.24
Investment in General Partner deferred income tax	—	0.12	—
Restructuring costs	0.13	0.08	0.08
Early retirement of debt	—	0.07	—
Core earnings per share attributable to Devon (non-GAAP)	$ 2.52	$ 4.91	$ 4.26

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 all our oil and gas derivative financial instruments as of December 31, 2015 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, 2015, a 10% change in the forward curves associated with our commodity derivative instruments would not have materially impacted our balance sheet at December 31, 2015.

Interest Rate Risk

At December 31, 2015, we had total debt of $13.1 billion. Of this amount, $11.7 billion bears fixed interest rates averaging 5.3%, and $1.4 billion is comprised of floating rate debt with interest rates averaging 1.1%. Our commercial paper borrowings typically have maturities between 1 and 90 days.

As of December 31, 2015, 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 3 month LIBOR rate. A 10% change in these forward curves would not have materially impacted our balance sheet at December 31, 2015.

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, 2015 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. Additionally, at December 31, 2015, we held foreign currency exchange forward contracts to hedge exposures to fluctuations in exchange rates on the Canadian-dollar cash and intercompany loans. The increase or decrease in the value of the forward contracts is offset by the increase or decrease to the U.S. dollar equivalent of the Canadian-dollar cash and intercompany loans. Based on the amount of the cash and intercompany loans as of December 31, 2015, 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, 2015 and 2014, and the related consolidated comprehensive statements of earnings, cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2015. We also have audited Devon Energy Corporation's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* 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, 2015 and 2014, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2015, 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, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Oklahoma City, Oklahoma
February 17, 2016

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED COMPREHENSIVE STATEMENTS OF EARNINGS

	Year Ended December 31,		
	2015	2014	2013
	(Millions, except per share amounts)		
Oil, gas and NGL sales	$ 5,382	$ 9,910	$ 8,522
Oil, gas and NGL derivatives	503	1,989	(191)
Marketing and midstream revenues	7,260	7,667	2,066
Total operating revenues	13,145	19,566	10,397
Lease operating expenses	2,104	2,332	2,268
Marketing and midstream operating expenses	6,420	6,815	1,553
General and administrative expenses	855	847	617
Production and property taxes	388	535	461
Depreciation, depletion and amortization	3,129	3,319	2,780
Asset impairments	20,820	1,953	1,976
Restructuring costs	78	46	54
Gains and losses on asset sales	—	(1,072)	9
Other operating items	78	93	112
Total operating expenses	33,872	14,868	9,830
Operating income (loss)	(20,727)	4,698	567
Net financing costs	517	526	417
Other nonoperating items	24	113	1
Earnings (loss) before income taxes	(21,268)	4,059	149
Income tax expense (benefit)	(6,065)	2,368	169
Net earnings (loss)	(15,203)	1,691	(20)
Net earnings (loss) attributable to noncontrolling interests	(749)	84	—
Net earnings (loss) attributable to Devon	$(14,454)	$ 1,607	$ (20)
Net earnings (loss) per share attributable to Devon:			
Basic	$ (35.55)	$ 3.93	$ (0.06)
Diluted	$ (35.55)	$ 3.91	$ (0.06)
Comprehensive earnings (loss):			
Net earnings (loss)	$(15,203)	$ 1,691	$ (20)
Other comprehensive earnings (loss), net of tax:			
Foreign currency translation	(559)	(465)	(548)
Pension and postretirement plans	10	(24)	45
Other comprehensive loss, net of tax	(549)	(489)	(503)
Comprehensive earnings (loss)	(15,752)	1,202	(523)
Comprehensive earnings (loss) attributable to noncontrolling interests	(749)	84	—
Comprehensive earnings (loss) attributable to Devon	$(15,003)	$ 1,118	$ (523)

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2015	2014	2013
	(Millions)		
Cash flows from operating activities:			
Net earnings (loss)	$(15,203)	$ 1,691	$ (20)
Adjustments to reconcile net earnings (loss) to net cash from operating activities:			
Depreciation, depletion and amortization	3,129	3,319	2,780
Asset impairments	20,820	1,953	1,976
Gains and losses on asset sales	—	(1,072)	9
Deferred income tax expense (benefit)	(5,828)	1,891	97
Derivatives and other financial instruments	(738)	(2,070)	135
Cash settlements on derivatives and financial instruments	2,688	104	277
Other noncash charges	537	457	309
Net change in working capital	(301)	50	(298)
Change in long-term other assets	285	(421)	10
Change in long-term other liabilities	(6)	79	161
Net cash from operating activities	5,383	5,981	5,436
Cash flows from investing activities:			
Capital expenditures	(5,308)	(6,988)	(6,502)
Acquisitions of property, equipment and businesses	(1,107)	(6,462)	(256)
Divestitures of property and equipment	107	5,120	419
Purchases of short-term investments	—	—	(1,076)
Redemptions of short-term investments	—	—	3,419
Redemptions of long-term investments	—	57	—
Other	(16)	89	(3)
Net cash from investing activities	(6,324)	(8,184)	(3,999)
Cash flows from financing activities:			
Borrowings of long-term debt, net of issuance costs	4,772	5,340	2,233
Repayments of long-term debt	(2,634)	(7,189)	—
Net short-term debt repayments	(307)	(385)	(1,872)
Stock option exercises	4	93	3
Sale of subsidiary units	654	—	—
Issuance of subsidiary units	25	410	—
Dividends paid on common stock	(396)	(386)	(348)
Distributions to noncontrolling interests	(254)	(235)	—
Other	(16)	(2)	4
Net cash from financing activities	1,848	(2,354)	20
Effect of exchange rate changes on cash	(77)	(29)	(28)
Net change in cash and cash equivalents	830	(4,586)	1,429
Cash and cash equivalents at beginning of period	1,480	6,066	4,637
Cash and cash equivalents at end of period	$ 2,310	$ 1,480	$ 6,066

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2015	December 31, 2014
	(Millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,310	$ 1,480
Accounts receivable	1,105	1,959
Derivatives, at fair value	43	1,993
Income taxes receivable	147	522
Other current assets	421	544
Total current assets	4,026	6,498
Property and equipment, at cost:		
Oil and gas, based on full cost accounting:		
Subject to amortization	78,190	75,738
Not subject to amortization	2,584	2,752
Total oil and gas	80,774	78,490
Midstream and other	10,380	9,695
Total property and equipment, at cost	91,154	88,185
Less accumulated depreciation, depletion and amortization	(72,086)	(51,889)
Property and equipment, net	19,068	36,296
Goodwill	5,032	6,303
Other long-term assets	1,406	1,540
Total assets	$ 29,532	$ 50,637
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 906	$ 1,400
Revenues and royalties payable	763	1,193
Short-term debt	976	1,432
Deferred income taxes	—	730
Other current liabilities	650	1,180
Total current liabilities	3,295	5,935
Long-term debt	12,137	9,830
Asset retirement obligations	1,370	1,339
Other long-term liabilities	853	948
Deferred income taxes	888	6,244
Stockholders' equity:		
Common stock, $0.10 par value. Authorized 1.0 billion shares; issued 418 million and 409 million shares in 2015 and 2014, respectively	42	41
Additional paid-in capital	4,996	4,088
Retained earnings	1,781	16,631
Accumulated other comprehensive earnings	230	779
Total stockholders' equity attributable to Devon	7,049	21,539
Noncontrolling interests	3,940	4,802
Total stockholders' equity	10,989	26,341
Commitments and contingencies (Note 18)		
Total liabilities and stockholders' equity	$ 29,532	$ 50,637

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Earnings	Treasury Stock	Noncontrolling Interests	Total Stockholders' Equity
	Shares	Amount						
					(Millions)			
Balance as of December 31, 2012	406	$ 41	$3,688	$ 15,778	$1,771	$—	$ —	$ 21,278
Net loss	—	—	—	(20)	—	—	—	(20)
Other comprehensive loss, net of tax	—	—	—	—	(503)	—	—	(503)
Stock option exercises	—	—	3	—	—	—	—	3
Common stock repurchased	—	—	—	—	—	(36)	—	(36)
Common stock retired	—	—	(36)	—	—	36	—	—
Common stock dividends	—	—	—	(348)	—	—	—	(348)
Share-based compensation	—	—	121	—	—	—	—	121
Share-based compensation tax benefits	—	—	4	—	—	—	—	4
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

See accompanying 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 2015, 2014 and 2013, no purchaser accounted for more than 10% of Devon's operating revenues.

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 periodically 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.

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, 2015, 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, 2015 and December 31, 2014, Devon held $75 million and $524 million, respectively, 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.

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 independent members of its Board of Directors and selected employees. EnLink and the General Partner also grant share-based awards to independent members of its Board of Directors and selected 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.

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.

Investments

Devon periodically invests excess cash in U.S. and Canadian treasury securities and other marketable securities. Devon considers securities with original contractual maturities in excess of three months but less than one year to be short-term investments. Investments with contractual maturities in excess of one year are classified as long-term, unless such investments are classified as trading or available-for-sale. Devon reports its investments and other marketable securities at fair value.

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 holding periods 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 upon disposal of oil and gas properties unless such disposal significantly alters the relationship between capitalized costs and proved reserves in a particular country. As discussed more fully in Note 2, the 2014 divestitures of certain Canadian assets significantly altered such relationship, and Devon recognized a gain, which is included as a separate item in the accompanying consolidated comprehensive statements of earnings.

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, 2015 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 performed annual impairment tests of goodwill in the fourth quarters of 2015, 2014 and 2013. No impairment of goodwill was required in 2013. However, write-downs were required in 2015 and 2014 based on the annual impairment test. EnLink's Texas, Louisiana and Crude and Condensate reporting segment goodwill were deemed impaired in 2015, and Devon's Canadian reporting unit goodwill was deemed impaired in 2014. 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 2015, EnLink's customer relationships were also evaluated for impairment, and a portion of these intangibles 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 Issued Accounting Standards

The FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. This ASU supersedes 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 and is required to be adopted using either the retrospective or cumulative effect (modified retrospective) transition method, with early adoption permitted in 2017. Devon is evaluating 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 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*. This ASU provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporations and securitization structures, should be consolidated. The ASU is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. This ASU is effective for Devon beginning January 1, 2016 and will be applied using the retrospective approach. This ASU will not have a material impact on Devon's consolidated financial statements and related disclosures.

The FASB issued ASU 2015-03, *Interest – Imputation of Interest (Topic 835): Simplifying the Presentation of Debt Issuance Costs* and ASU 2015-15, *Interest – Imputation of Interest (Topic 835): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements.* These ASUs require debt issuance costs related to a recognized debt liability, except for those related to revolving credit facilities, to be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability rather than as an asset. These ASUs are effective for Devon beginning January 1, 2016 and will be applied using the retrospective approach. These ASUs will not have a material impact on Devon's consolidated financial statements and related disclosures.

The FASB issued ASU 2015-17, *Balance Sheet Classification of Deferred Taxes*. This ASU requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. This ASU is effective for annual and interim periods beginning in 2017 and can be applied prospectively or retrospectively, with early adoption permitted. This ASU will be early-adopted by Devon, effective January 1, 2016 and will be applied using the retrospective approach. This ASU will not have a material impact on Devon's consolidated financial statements and related disclosures.

2. Acquisitions and Divestitures

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	1.0x
Converted shares	48.4
Crosstex Energy, Inc. common share price (1)	$37.60
Crosstex Energy, Inc. consideration	$1,823
Fair value of noncontrolling interests 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 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, net	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 consideration and fair value of noncontrolling interests	$ 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.

EnLink Acquisitions

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 31	LPC	$108	—	$ 30	$30	$ 43	$ 5
March 16	Coronado	$240	$360	$302	$18	$281	$(1)
October 1	Matador	$145	—	$ 36	$ 9	$ 99	$ 1

On January 7, 2016, EnLink also acquired Anadarko Basin gathering and processing midstream assets from Tall Oak for approximately $1.5 billion, subject to certain adjustments. EnLink paid approximately $800 million of cash at the time of closing, primarily funded with the issuance of EnLink preferred units, with another $500 million of cash to be paid within 24 months. The remainder of the purchase price consisted of approximately 15.6 million General Partner common units.

EnLink Dropdowns

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.

Devon Acquisitions

On February 28, 2014, Devon completed its acquisition of interests in certain affiliates of GeoSouthern for approximately $6.0 billion. Devon funded the acquisition with cash on hand and debt financing. In connection with the GeoSouthern transaction, Devon acquired approximately 82,000 net acres (unaudited) located in DeWitt and Lavaca counties in south Texas. The transaction was accounted for using the acquisition method, which requires, among other things, that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date.

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

Cash and cash equivalents	$ 95
Other current assets	256
Proved properties	5,026
Unproved properties	1,007
Midstream assets	86
Current liabilities	(434)
Long-term liabilities	(6)
Net assets acquired	$6,030

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. A preliminary allocation of the purchase price at December 31, 2015 was $386 million to unproved properties and $113 million to proved properties and gathering systems.

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 $850 million of cash and $659 million of equity.

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, 2013. 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	2013
	(Millions)	
Total operating revenues	$20,213	$12,979
Net earnings	$ 1,716	$ 35
Noncontrolling interests	$ 97	$ 45
Net earnings (loss) attributable to Devon	$ 1,619	$ (10)
Net earnings (loss) per common share attributable to Devon	$ 3.94	$ (0.02)

Asset Divestitures

During 2014, Devon divested certain properties located throughout Canada and the U.S. as part of its asset portfolio transformation.

Canada

In the second quarter of 2014, Devon sold Canadian conventional assets for $2.8 billion ($3.125 billion Canadian dollars) and recognized a gain totaling $1.1 billion ($0.6 billion after-tax). This gain is included as a separate item in the accompanying consolidated comprehensive statements of earnings. Included in the gain calculation were asset retirement obligations of approximately $700 million assumed by the purchaser as well as the derecognition of approximately $700 million of goodwill allocated to the sold assets. In conjunction with the divestiture, Devon repatriated approximately $2.8 billion of proceeds to the U.S. in the second quarter of 2014, which was utilized to repay commercial paper and term loan balances. Between collecting the divestiture proceeds and repatriating 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.

U.S.

In the third quarter of 2014, Devon sold certain U.S. assets for $2.2 billion. Additionally, approximately $200 million of asset retirement obligations were assumed by the purchaser. No gain or loss was recognized on the sale. These proceeds were used toward the early retirement of $1.9 billion in senior notes in November 2014 as discussed in Note 13.

3. Derivative Financial Instruments

Commodity Derivatives

As of December 31, 2015, 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.

	Call Options Sold	
Period	**Volume (Bbls/d)**	**Weighted Average Price ($/Bbl)**
Q1-Q4 2016	18,500	$73.18

	Oil Basis Swaps		
Period	**Index**	**Volume (Bbls/d)**	**Weighted Average Differential to WTI ($/Bbl)**
Q1-Q4 2016	Western Canadian Select	5,249	$(13.67)
Q1-Q4 2016	West Texas Sour	5,000	$ (0.53)
Q1-Q4 2016	Midland Sweet	13,000	$ 0.25

As of December 31, 2015, 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		Call Options Sold	
Period	**Volume (MMBtu/d)**	**Weighted Average Price ($/MMBtu)**	**Volume (MMBtu/d)**	**Weighted Average Price ($/MMBtu)**
Q1-Q4 2016	54,650	$3.17	400,000	$4.30

	Natural Gas Basis Swaps		
Period	**Index**	**Volume (MMBtu/d)**	**Weighted Average Differential to Henry Hub ($/MMBtu)**
Q1-Q4 2016	Panhandle Eastern Pipe Line	175,000	$(0.34)
Q1-Q4 2016	El Paso Natural Gas	125,000	$(0.12)
Q1-Q4 2016	Houston Ship Channel	30,000	$ 0.11
Q1-Q4 2016	Transco Zone 4	70,000	$ 0.01
Q1-Q4 2017	Panhandle Eastern Pipe Line	150,000	$(0.34)
Q1-Q4 2017	El Paso Natural Gas	50,000	$(0.14)
Q1-Q4 2017	Houston Ship Channel	35,000	$ 0.06
Q1-Q4 2017	Transco Zone 4	185,000	$ 0.03

As of December 31, 2015, 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 2016-Q4 2016	Ethane	571 MBbls	$ 0.29/gal	Index
Q1 2016-Q4 2016	Propane	812 MBbls	Index	$0.81/gal
Q1 2016-Q4 2016	Normal Butane	113 MBbls	Index	$0.61/gal
Q1 2016-Q4 2016	Natural Gasoline	61 MBbls	Index	$1.02/gal
Q1 2016-Q1 2017	Natural Gas	13,829 MMBtu/d	$2.65/MMBtu	Index

Interest Rate Derivatives

As of December 31, 2015, Devon had the following open interest rate derivative positions:

Notional (Millions)	Rate Received	Rate Paid	Expiration
$100	Three Month LIBOR	0.92%	December 2016
$100	1.76%	Three Month LIBOR	January 2019
$750	Three Month LIBOR	2.98%	December 2048 (1)

(1) Mandatory settlement in December 2018.

Foreign Currency Derivatives

As of December 31, 2015, Devon had the following open foreign currency derivative position:

	Forward Contract			
Currency	Contract Type	CAD Notional (Millions)	Weighted Average Fixed Rate Received (CAD-USD)	Expiration
Canadian Dollar	Sell	$3,560	0.723	March 2016

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, 2015	2014	2013
		(Millions)	
Commodity derivatives:			
Oil, gas and NGL derivatives	$503	$1,989	$(191)
Marketing and midstream revenues	9	22	—
Interest rate derivatives:			
Other nonoperating items	(20)	(1)	—
Foreign currency derivatives:			
Other nonoperating items	246	60	56
Net gains (losses) recognized	$738	$2,070	$(135)

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

	December 31, 2015	December 31, 2014
	(Millions)	
Commodity derivative assets:		
Derivatives, at fair value	$ 34	$1,984
Other long-term assets	1	11
Interest rate derivative assets:		
Derivatives, at fair value	1	1
Other long-term assets	1	—
Foreign currency derivative assets:		
Derivatives, at fair value	8	8
Total derivative assets	$ 45	$2,004
Commodity derivative liabilities:		
Other current liabilities	$ 14	$ 28
Other long-term liabilities	4	28
Interest rate derivative liabilities:		
Other current liabilities	—	1
Other long-term liabilities	22	—
Foreign currency derivative liabilities:		
Other current liabilities	8	—
Total derivative liabilities	$ 48	$ 57

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.

Devon did not have an annual long-term incentive grant in 2013 due to revisions in the timing of the employee compensation cycle. The annual long-term incentive grant related to 2013 performance was granted in February 2014.

The following table presents the effects of share-based compensation included in Devon's accompanying consolidated comprehensive statements of earnings. Gross G&A for the years ended December 31, 2015 and 2014 includes $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 2014 in conjunction with the divestiture of Devon's Canadian conventional assets. For the year ended December 31, 2014, approximately $15 million of associated expense for these accelerated awards is included in restructuring costs in the accompanying consolidated comprehensive statements of earnings.

	Year Ended December 31,		
	2015	2014	2013
		(Millions)	
Gross general and administrative expense for share-based compensation	$225	$199	$157
Share-based compensation expense capitalized pursuant to the full cost method of accounting for oil and gas properties	$ 63	$ 53	$ 60
Related income tax benefit	$ 45	$ 42	$ 29

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		Performance-Based Restricted Stock Awards		Performance Share Units	
	Awards and Units	Weighted Average Grant-Date Fair Value	Awards	Weighted Average Grant-Date Fair Value	Units	Weighted Average Grant-Date Fair Value
	(Thousands, except fair value data)					
Unvested at 12/31/14	4,304	$60.85	380	$59.41	1,477	$70.90
Granted	2,771	$63.57	236	$62.02	786	$84.14
Vested	(1,834)	$60.33	(153)	$59.49	(337)	$66.00
Forfeited	(503)	$62.22	(29)	$64.18	(67)	$79.20
Unvested at 12/31/15	4,738	$62.49	434	$60.48	1,859(1)	$76.17

(1) A maximum of 3.7 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.

	2015	2014	2013
		(Millions)	
Restricted stock awards and units	$101	$112	$141
Performance-based restricted stock awards	$ 8	$ 10	$ 5
Performance share units	$ 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, 2015.

	Restricted Stock Awards and Units	Performance-Based Restricted Stock Awards	Performance Share Units
Unrecognized compensation cost (millions)	$198	$ 6	$ 45
Weighted average period for recognition (years)	2.5	2.6	1.8

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 zero 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 zero 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 senior management. 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 two- or 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.

	2015	2014	2013
Grant-date fair value	\$81.99 – \$85.05	\$70.18 – \$81.05	\$61.27 – \$63.48
Risk-free interest rate	1.06%	0.54%	0.26% – 0.36%
Volatility factor	26.2%	28.8%	30.3%
Contractual term (years)	2.89	2.89	3.0

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 zero 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 2015, 2014 and 2013. 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, 2014	4,218	$70.56		
Granted	—	$ —		
Exercised	(63)	$64.25		
Expired	(680)	$84.36		
Forfeited	(27)	$66.71		
Outstanding at December 31, 2015	3,448	$67.98	2.41	$—
Vested and expected to vest at December 31, 2015	3,448	$67.98	2.41	$—
Exercisable at December 31, 2015	3,448	$67.98	2.41	$—

The aggregate intrinsic value of stock options that were exercised during 2015, 2014 and 2013 was $0.2 million, $9 million and $0.3 million, respectively. As of December 31, 2015, Devon had no unrecognized compensation cost related to unvested stock options.

EnLink Share-Based Awards

In March 2015, the General Partner and EnLink issued restricted incentive units as bonus payments to officers and certain employees for 2014. The combined grant fair value was $7 million, and the total cost was recognized in the first quarter of 2015 due to the awards vesting immediately.

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, 2015.

	General Partner		EnLink	
	Restricted Incentive Units	Performance Units	Restricted Incentive Units	Performance Units
Unrecognized compensation cost (millions)	$ 17	$ 3	$ 16	$ 3
Weighted average period for recognition (years)	1.6	2.0	1.6	2.0

5. Asset Impairments

The following table presents the asset impairments recognized in 2015, 2014 and 2013.

	Year Ended December 31,		
	2015	2014	2013
		(Millions)	
U.S. oil and gas assets	$17,992	$ —	$1,110
Canada oil and gas assets	1,257	—	843
Canada goodwill	—	1,941	—
EnLink goodwill	1,328	—	—
EnLink other intangible assets	223	—	—
Other assets	20	12	23
Total asset impairments	$20,820	$1,953	$1,976

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 21.

Goodwill and Other Intangible Assets Impairments

In 2015, Devon recognized goodwill and other intangible asset impairments related to EnLink's business. In 2014, Devon recognized a goodwill impairment related to its Canadian reporting unit. Additional information regarding these impairments is discussed in Note 12.

6. Restructuring Costs

Canadian Reduction in Work Force

In 2015, Devon recognized $24 million of employee related and other costs associated with the reduction in work force made subsequent to the completion of the Jackfish development projects and a decrease in planned 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.

Canadian Divestitures

During 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.

Office Consolidation

Near the end of 2012, Devon consolidated its U.S. personnel into a single operations group centrally located at the company's corporate headquarters in Oklahoma City. As a result, Devon closed its office in Houston, transferred operational responsibilities for assets in south Texas, east Texas and Louisiana to Oklahoma City and incurred $134 million of restructuring costs associated with the consolidation. The employee severance and retention costs included amounts related to cash severance costs and accelerated vesting of share-based grants. The lease obligations and other costs are associated with certain office space that is subject to non-cancellable operating lease agreements that Devon ceased using as part of the office consolidation.

Due to a lack of demand for vacated office space in which Devon's remaining leases are located, in 2015, Devon recognized an additional $54 million expense as a result of its inability to fully sublease remaining office space.

Financial Statement Presentation

The following table summarizes restructuring costs presented in the accompanying consolidated comprehensive statements of earnings.

	Year Ended December 31,		
	2015	2014	2013
		(Millions)	
Office consolidation and offshore divestiture:			
Employee severance and retention	$—	$—	$ 13
Lease obligations and other	54	—	41
Canada divestitures:			
Employee severance and retention	11	42	—
Lease obligations and other	13	4	—
Restructuring costs	$ 78	$ 46	$ 54

The following table summarizes Devon's restructuring liabilities.

	Other Current Liabilities	Other Long-term Liabilities	Total
		(Millions)	
Balance as of December 31, 2013	$ 27	$ 18	$ 45
Changes due to office consolidation and offshore divestiture	(18)	(11)	(29)
Changes due to Canadian divestitures	4	—	4
Balance as of December 31, 2014	13	7	20
Changes due to office consolidation and offshore divestiture	1	46	47
Changes due to Canadian divestitures	(1)	10	9
Balance as of December 31, 2015	$ 13	$ 63	$ 76

7. Income Taxes

Income Tax Expense (Benefit)

The following table presents Devon's income tax components.

	Year Ended December 31, 2015	2014	2013
		(Millions)	
Current income tax expense (benefit):			
U.S. federal	$ (243)	$ 152	$ 73
Various states	(8)	18	(5)
Canada and various provinces	14	307	4
Total current tax expense (benefit)	(237)	477	72
Deferred income tax expense (benefit):			
U.S. federal	(5,033)	1,610	198
Various states	(336)	93	59
Canada and various provinces	(459)	188	(160)
Total deferred tax expense (benefit)	(5,828)	1,891	97
Total income tax expense (benefit)	$(6,065)	$2,368	$ 169

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, 2015	2014	2013
Total income tax expense (benefit) (millions)	$(6,065)	$2,368	$169
U.S. statutory income tax rate	(35)%	35%	35%
Non-deductible goodwill and intangible impairment	2%	23%	0%
Taxation on Canadian operations	1%	(4)%	9%
State income taxes	(1)%	2%	23%
Repatriations	0%	2%	65%
Deferred tax asset valuation allowance	4%	0%	0%
Other	0%	0%	(19)%
Effective income tax rate	(29)%	58%	113%

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.

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 examination 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 operation conditions (particularly as related to prevailing oil and gas prices) and changing tax laws.

2015

In the third and fourth quarters of 2015, EnLink recorded goodwill and intangibles impairments of approximately $1.6 billion. These impairments are not deductible for purposes of calculating income tax and, therefore, have an impact on 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 we recognized a $967 million valuation allowance that impacted the effective tax rate and is discussed in the next section.

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, respectively. These transactions are not deductible for purposes of calculating income tax and therefore have an impact on 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 divestiture closing and due to the availability of additional tax deductions, 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.

2013

In the second and fourth quarters of 2013, Devon repatriated to the U.S. a total of $4.3 billion of its cash held outside of the U.S. In the fourth quarter of 2013, Devon announced plans to divest of its Canadian conventional assets. These events resulted in an incremental income tax expense of $97 million. The incremental expense included $180 million of current income tax expense offset by $83 million of deferred income tax benefit. The $83 million deferred tax benefit was comprised of $180 million of deferred tax benefits that offset the incremental current income tax expense and an additional $97 million of deferred income tax expense accrued in the fourth quarter for assumed repatriations.

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, 2015	December 31, 2014
	(Millions)	
Deferred tax assets:		
Property and equipment	$ 490	$ —
Asset retirement obligations	485	458
Accrued liabilities	160	150
Net operating loss carryforwards	175	200
Pension benefit obligations	106	113
Other	162	180
Total deferred tax assets before valuation allowance	1,578	1,101
Less: valuation allowance	(967)	—
Net deferred tax assets	611	1,101
Deferred tax liabilities:		
Property and equipment	(1,187)	(6,940)
Fair value of financial instruments	—	(699)
Long-term debt	(36)	(115)
Other	(271)	(160)
Total deferred tax liabilities	(1,494)	(7,914)
Net deferred tax liability	$ (883)	$(6,813)

At December 31, 2015, Devon has $175 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 $495 million of Canadian carryforwards that expire between 2030 and 2035, $275 million of U.S. state carryforwards that expire between 2018 and 2035 and $205 million of carryforwards related to EnLink's operations that expire between 2028 and 2035. In the current environment, Devon expects the tax benefits from the Canadian and EnLink net operating loss carryforwards to be utilized in 2017 and beyond. Devon also has $6 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.

At the end of 2015, Devon had deferred tax assets that largely resulted from the full cost impairments recognized during 2015. As a result of the recent cumulative financial losses, Devon recorded a $967 million, or 100%, valuation allowance against the U.S. deferred tax assets as of December 31, 2015. 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, 2015, Devon's unremitted foreign earnings from its other international operations totaled approximately $1.2 billion. All but $37 million of the $1.2 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 $37 million of unremitted earnings deemed not to be indefinitely reinvested, Devon has recognized a $10 million deferred tax liability associated with such unremitted earnings as of December 31, 2015.

Unrecognized Tax Benefits

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

	December 31, 2015	December 31, 2014
	(Millions)	
Balance at beginning of year	$ 241	$243
Tax positions taken in prior periods	(19)	—
Tax positions taken in current year	31	—
Accrual of interest related to tax positions taken	(5)	2
Settlements	(108)	—
Foreign currency translation	(9)	(4)
Balance at end of year	$ 131	$241

Devon's unrecognized tax benefit balance at December 31, 2015 and 2014 included $29 million and $34 million, respectively, of interest and penalties. If recognized, $131 million of Devon's unrecognized tax benefits as of December 31, 2015 would affect Devon's effective income tax rate. 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	2008-2015
Various U.S. states	2008-2015
Canada Federal	2003-2015
Various Canadian provinces	2003-2015

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. As a result, Devon cannot reasonably anticipate the extent that the liabilities for unrecognized tax benefits will increase or decrease within the next twelve months.

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,		
	2015	2014	2013
	(Millions, except per share amounts)		
Net earnings (loss):			
Net earnings (loss) attributable to Devon	$(14,454)	$1,607	$ (20)
Attributable to participating securities	(5)	(17)	(2)
Basic and diluted earnings (loss)	$(14,459)	$1,590	$ (22)
Common shares:			
Common shares outstanding - total	412	409	406
Attributable to participating securities	(5)	(4)	(4)
Common shares outstanding - basic	407	405	402
Dilutive effect of potential common shares issuable	—	2	—
Common shares outstanding - diluted	407	407	402
Net earnings (loss) per share attributable to Devon:			
Basic	$ (35.55)	$ 3.93	$(0.06)
Diluted	$ (35.55)	$ 3.91	$(0.06)
Antidilutive options (1)	4	3	7

(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,		
	2015	2014	2013
	(Millions)		
Foreign currency translation:			
Beginning accumulated foreign currency translation	$ 983	$1,448	$1,996
Change in cumulative translation adjustment	(621)	(499)	(574)
Income tax benefit	62	34	26
Ending accumulated foreign currency translation	424	983	1,448
Pension and postretirement benefit plans:			
Beginning accumulated pension and postretirement benefits	(204)	(180)	(225)
Net actuarial gain (loss) and prior service cost arising in current year	(5)	(57)	48
Recognition of net actuarial loss and prior service cost in earnings (1)	21	20	24
Income tax benefit (expense)	(6)	13	(27)
Ending accumulated pension and postretirement benefits	(194)	(204)	(180)
Accumulated other comprehensive earnings, net of tax	$ 230	$ 779	$1,268

(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 15 for additional details.

10. Supplemental Information to Statements of Cash Flows

	Year Ended December 31,		
	2015	2014	2013
		(Millions)	
Net change in working capital accounts:			
Accounts receivable	$ 942	$ 128	$(288)
Income taxes receivable	384	(467)	29
Other current assets	(57)	(222)	20
Accounts payable	(190)	(68)	26
Revenues and royalties payable	(526)	133	35
Income taxes payable	(275)	30	—
Other current liabilities	(579)	516	(120)
Net change in working capital	$(301)	$ 50	$(298)
Interest paid (net of capitalized interest)	$ 494	$ 514	$ 406
Income taxes paid (received)	$(279)	$ 899	$ 13

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. EnLink's noncash acquisition activity during 2015 included a portion of the Coronado transaction.

As discussed in Note 2, Devon's acquisition of certain Powder River Basin assets included noncash common stock issuance totaling $199 million.

11. Accounts Receivable

Components of accounts receivable include the following:

	December 31, 2015	December 31, 2014
	(Millions)	
Oil, gas and NGL sales	$ 362	$ 723
Joint interest billings	211	475
Marketing and midstream revenues	520	706
Other	30	71
Gross accounts receivable	1,123	1,975
Allowance for doubtful accounts	(18)	(16)
Net accounts receivable	$1,105	$1,959

12. Goodwill and Other Intangible Assets

Goodwill

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

	U.S.	Canada	EnLink	Total
		(Millions)		
Balance as of December 31, 2013	$2,618	$ 2,838	$ 402	$ 5,858
Acquired during period	—	—	3,283	3,283
Asset divestitures	—	(706)	—	(706)
Impairment	—	(1,941)	—	(1,941)
Foreign currency translation adjustments	—	(191)	—	(191)
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

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, 2013	$ 326	$ —	$ 76	$—	$ —	$ 402
Acquired during period	842	787	114	113	1,427	3,283
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

Included in the assets Devon contributed to EMH was $402 million of goodwill. See Note 2 for discussion of acquired goodwill resulting from EnLink's formation in 2014 and acquisitions in 2015.

Asset Divestitures

In conjunction with the Canadian conventional asset divestitures in 2014, Devon removed $706 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. Furthermore, due to the continued impact of declining commodity prices and EnLink unit price, an update was performed as of December 31, 2015. As a result of these tests, noncash goodwill impairments were recorded related to EnLink's Texas, Louisiana and Crude and Condensate reporting units in 2015.

In the fourth quarter of 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. This conclusion was largely based on the significant decline in benchmark oil prices, particularly after OPEC's decision not to reduce its production targets that was announced in late November 2014. Devon's Canadian goodwill was originally recognized in 2001 as a result of a business combination consisting almost entirely of conventional gas assets that Devon no longer owns.

Other Intangible Assets

During 2015, EnLink's customer relationships were also evaluated for impairment due to the factors in the aforementioned goodwill impairment analysis. 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. This assessment resulted in a $223 million noncash impairment related to EnLink's Crude and Condensate customer relationships in 2015.

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

	December 31, 2015	December 31, 2014
	(Millions)	
Customer relationships	$745	$569
Accumulated amortization	(55)	(36)
Net intangibles	$690	$533

The weighted-average amortization period for the customer relationships is 12.6 years. Amortization expense for intangibles was approximately $56 million and $36 million for the years ended December 31, 2015 and December 31, 2014, respectively. The remaining aggregate amortization expense is estimated to be approximately $46 million each of the next five years.

13. Debt and Related Expenses

A summary of debt is as follows:

	December 31, 2015	December 31, 2014
	(Millions)	
Devon debt		
Commercial paper	$ 626	$ 932
Floating rate due December 15, 2015	—	500
Floating rate due December 15, 2016	350	350
8.25% due July 1, 2018	125	125
2.25% due December 15, 2018	750	750
6.30% due January 15, 2019	700	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	850	—
7.50% due September 15, 2027	150	150
7.875% due September 30, 2031	1,250	1,250
7.95% due April 15, 2032	1,000	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	—
Net discount on debentures and notes	(28)	(18)
Total Devon debt	10,023	9,239
EnLink debt		
Credit facilities	414	237
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	—
5.60% due April 1, 2044	350	350
5.05% due April 1, 2045	450	300
Net premium on debentures and notes	13	23
Total EnLink debt	3,090	2,023
Total debt	13,113	11,262
Less amount classified as short-term debt (1)	976	1,432
Total long-term debt	$12,137	$ 9,830

(1) 2015 short-term debt consists of $626 million of commercial paper and the $350 million floating rate due on December 15, 2016. 2014 short-term debt consists of $932 million of commercial paper and $500 million floating rate due on December 15, 2015.

Debt maturities as of December 31, 2015, excluding premiums and discounts, are as follows (millions):

2016	$ 976
2017	—
2018	875
2019	1,100
2020	414
Thereafter	9,763
Total	$13,128

Credit Lines

Devon has 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. 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 $3.8 million that is payable quarterly in arrears. As of December 31, 2015, there were no borrowings under the Senior Credit Facility.

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 full cost ceiling impairments or goodwill impairments. As of December 31, 2015, Devon was in compliance with this covenant with a debt-to-capitalization ratio of 23.7%.

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. As of December 31, 2015, Devon's outstanding commercial paper borrowings had a weighted-average borrowing rate of 0.63%.

Issuance of Senior Notes

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.

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 fund the cash portion of these acquisitions.

Retirement of Senior Notes

In November 2014, Devon redeemed $1.9 billion of senior notes prior to their scheduled maturity, primarily with proceeds received from its asset divestitures. The redemption includes the 2.4% $500 million senior notes due 2016, the 1.2% $650 million senior notes due 2016 and the 1.875% $750 million senior notes due 2017. The notes were redeemed for $1.9 billion, which included 100% of the principal amount and a make-whole premium of $40 million. On the date of redemption, these notes also had an unamortized discount of $2 million and unamortized debt issuance costs of $6 million. The make-whole premium, unamortized discounts and debt issuance costs are included in net financing costs on the accompanying 2014 consolidated comprehensive statement of earnings.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes outstanding at December 31, 2015 and 2014, as listed in the table presented at the beginning of this note.

GeoSouthern Debt

In December 2013, in conjunction with the planned GeoSouthern acquisition, Devon issued $2.25 billion aggregate principal amount of fixed and floating rate senior notes. Devon repaid the floating rate senior notes due 2015 upon maturity and redeemed the 1.2% senior notes due December 15, 2016 in November 2014. As of December 31, 2015, the floating rate senior notes due 2016 and the 2.25% senior notes due December 15, 2018 were outstanding. The floating rate senior notes due 2016 bear interest at a rate equal to three-month LIBOR plus 0.54%, which will be reset quarterly.

Other Notes

In 2012, 2011, 2009 and 2002, Devon issued senior notes that are unsecured and unsubordinated obligations of Devon. Devon used the net proceeds to repay outstanding commercial paper, credit facility borrowings and other long-term debt. The schedule below summarizes the key terms of these notes (millions).

	Date Issued			
	May 2012	**July 2011**	**January 2009**	**March 2002**
3.25% due May 15, 2022	$1,000	$ —	$—	$ —
4.75% due May 15, 2042	750	—	—	—
4.00% due July 15, 2021	—	500	—	—
5.60% due July 15, 2041	—	1,250	—	—
6.30% due January 15, 2019	—	—	700	—
7.95% due April 15, 2032	—	—	—	1,000
Discount and issuance costs	(28)	(24)	(8)	(14)
Net proceeds	$1,722	$1,726	$692	$ 986

Ocean Debt

On April 25, 2003, Devon merged with Ocean Energy, Inc. and assumed certain debt instruments. The table below summarizes the debt assumed that remains outstanding as of December 31, 2015, including the fair value of the debt at April 25, 2003 and the effective interest rate of the debt after determining the fair values using

April 25, 2003 market interest rates. The premiums resulting from fair values exceeding face values are being amortized using the effective interest method. Both notes are general unsecured obligations of Devon.

Debt Assumed	Fair Value of Debt Assumed (Millions)	Effective Rate of Debt Assumed
8.25% due July 2018 (principal of $125 million)	$147	5.5%
7.50% due September 2027 (principal of $150 million)	$169	6.5%

7.875% Debentures due September 30, 2031

In October 2001, Devon, through Devon Financing, a wholly owned finance subsidiary, sold debentures, which are unsecured and unsubordinated obligations of Devon Financing. Devon has fully and unconditionally guaranteed, on an unsecured and unsubordinated basis, the obligations of Devon Financing under the debt securities. The proceeds were used to fund a portion of the Anderson Exploration acquisition.

EnLink Debt

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

The table below summarizes the fair value of EnLink's debt as of March 7, 2014, the formation date of EnLink. The premiums are being amortized using the effective interest method.

	March 7, 2014 Fair Value of Debt (Millions)	Effective Rate of Debt
8.875% due February 2018 (principal of $725 million) (1)	$ 760	7.7%
7.125% due June 2022 (principal of $197 million)	226	5.3%
Credit facilities	468	
Total long-term debt	$1,454	

(1) The 2018 senior notes were redeemed on April 18, 2014.

In February 2015, the commitments under EnLink's $1.0 billion unsecured revolving credit facility were increased to $1.5 billion, and the maturity date was extended by a year to March 6, 2020. As of December 31, 2015, there were $11 million in outstanding letters of credit and $414 million outstanding borrowings, with a weighted-average borrowing rate of 1.7%, 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, 2015, the General Partner had no outstanding borrowings under the $250 million credit facility. EnLink and the General Partner were in compliance with all financial covenants in their respective credit facilities as of December 31, 2015.

In March 2014, EnLink issued $1.2 billion aggregate principal amount of unsecured senior notes, consisting of $400 million of its 2.70% senior notes due 2019, $450 million of its 4.40% senior notes due 2024 and $350 million of its 5.60% senior notes due 2044, at discounts of their face value. EnLink used the net proceeds to redeem the 2018 senior notes, reduce outstanding credit facility borrowings, for capital expenditures and for general operations.

In November 2014, EnLink issued $100 million of its 4.40% senior notes due 2024 and $300 million of its 5.05% senior notes due 2045, at a premium and discount, respectively, of their face value. The 2024 notes were offered as an additional issue of EnLink's outstanding 4.40% senior notes due 2024, issued in March 2014. The 2024 notes issued in March 2014 and November 2014 are treated as a single class of debt securities and have identical terms, other than the issue date. EnLink used the net proceeds for capital expenditures and for general operations.

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,		
	2015	2014	2013
		(Millions)	
Interest based on debt outstanding	$565	$532	$466
Early retirement of debt	—	48	—
Capitalized interest	(62)	(70)	(56)
Other fees and expenses	20	26	27
Interest expense	523	536	437
Interest income	(6)	(10)	(20)
Net financing costs	$517	$526	$417

14. Asset Retirement Obligations

The following table presents the changes in asset retirement obligations.

	Year Ended December 31,	
	2015	2014
	(Millions)	
Asset retirement obligations as of beginning of period	$1,399	$ 2,228
Liabilities incurred	63	97
Liabilities settled and divested (1)	(89)	(1,009)
Revision of estimated obligation	62	70
Accretion expense on discounted obligation	75	89
Foreign currency translation adjustment	(96)	(76)
Asset retirement obligations as of end of period	1,414	1,399
Less current portion	44	60
Asset retirement obligations, long-term	$1,370	$ 1,339

(1) During 2014, Devon reduced its asset retirement obligation by $953 million for those obligations that were assumed by purchasers of Devon's Canadian and U.S. divested oil and gas properties.

15. 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 $22 million and $25 million at December 31, 2015 and 2014, 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, 2015 and 2014. Devon's benefit obligations and plan assets are measured each year as of December 31. The projected benefit obligations for Devon's qualified plans were fully funded as of December 31, 2015 and 2014.

	Pension Benefits		Postretirement Benefits	
	2015	2014	2015	2014
	(Millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$1,377	$1,177	$ 24	$ 24
Service cost	33	30	1	1
Interest cost	52	55	1	1
Actuarial loss (gain)	(68)	203	(2)	—
Plan amendments	—	—	1	—
Plan settlements	—	(4)	—	—
Foreign exchange rate changes	(6)	(3)	—	—
Participant contributions	—	—	2	2
Benefits paid	(80)	(81)	(4)	(4)
Benefit obligation at end of year	1,308	1,377	23	24
Change in plan assets:				
Fair value of plan assets at beginning of year	1,149	1,006	—	—
Actual return on plan assets	(16)	200	—	—
Employer contributions	11	29	2	2
Participant contributions	—	—	2	2
Plan settlements	—	(4)	—	—
Benefits paid	(80)	(81)	(4)	(4)
Foreign exchange rate changes	(5)	(1)	—	—
Fair value of plan assets at end of year	1,059	1,149	—	—
Funded status at end of year	$ (249)	$ (228)	$ (23)	$ (24)
Amounts recognized in balance sheet:				
Other long-term assets	$ 2	$ 22	$—	$—
Other current liabilities	(12)	(10)	(3)	(3)
Other long-term liabilities	(239)	(240)	(20)	(21)
Net amount	$ (249)	$ (228)	$ (23)	$ (24)
Amounts recognized in accumulated other comprehensive earnings:				
Net actuarial loss (gain)	$ 302	$ 317	$ (11)	$ (11)
Prior service cost (credit)	14	19	(6)	(9)
Total	$ 316	$ 336	$ (17)	$ (20)

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 $11 million and $10 million for 2015 and 2014, respectively, which were transferred from the trusts established for the nonqualified plans.

Certain of Devon's pension plans have a projected benefit obligation and accumulated benefit obligation in excess of plan assets at December 31, 2015 and 2014, as presented in the following table.

	December 31, 2015	December 31, 2014
	(Millions)	
Projected benefit obligation	$244	$250
Accumulated benefit obligation	$199	$191
Fair value of plan assets	$—	$—

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		
	2015	2014	2013	2015	2014	2013
	(Millions)					
Net periodic benefit cost:						
Service cost	$ 33	$ 30	$ 36	$ 1	$ 1	$ 1
Interest cost	52	55	51	1	1	1
Expected return on plan assets	(58)	(54)	(62)	—	—	—
Curtailment and settlement expense	—	1	—	—	—	—
Recognition of net actuarial loss (gain) (1)	20	18	22	(1)	(1)	(1)
Recognition of prior service cost (1)	4	4	4	(2)	(2)	(1)
Total net periodic benefit cost (2)	51	54	51	(1)	(1)	—
Other comprehensive loss (earnings):						
Actuarial loss (gain) arising in current year	5	57	(39)	(1)	—	(3)
Prior service cost (credit) arising in current year	—	—	2	1	—	(8)
Recognition of net actuarial loss, including settlement expense, in net periodic benefit cost	(20)	(19)	(22)	1	1	1
Recognition of prior service cost, including curtailment, in net periodic benefit cost	(4)	(4)	(4)	1	2	1
Total other comprehensive loss (earnings)	(19)	34	(63)	2	3	(9)
Total recognized	$ 32	$ 88	$ (12)	$ 1	$ 2	$ (9)

(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.

The following table presents the estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive earnings into net periodic benefit cost during 2016.

	Pension Benefits	Postretirement Benefits
	(Millions)	
Net actuarial loss (gain)	$22	$(2)
Prior service cost (credit)	4	(1)
Total	$26	$(3)

Assumptions

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

	Pension Benefits			Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Assumptions to determine benefit obligations:						
Discount rate	4.25%	3.90%	4.80%	3.63%	3.25%	3.65%
Rate of compensation increase	4.49%	4.49%	4.48%	N/A	N/A	N/A
Assumptions to determine net periodic benefit cost:						
Discount rate	3.90%	4.80%	3.85%	3.25%	3.65%	3.30%
Rate of compensation increase	4.49%	4.49%	4.48%	N/A	N/A	N/A
Expected return on plan assets	5.22%	5.42%	5.48%	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 2015 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 2015 benefit obligation for the other postretirement medical plans, a 7.6% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2016. The rate was assumed to decrease annually to an ultimate rate of 5% in the year 2029 and remain at that level thereafter. Assumed health care cost-trend rates affect the amounts reported for retiree health care costs. A one-percentage-point change in the assumed health care cost-trend rates would have changed the postretirement benefits obligation as of December 31, 2015 by less than $1 million and would change the 2015 service and interest cost components of net periodic benefit cost by less than $1 million.

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. The following table presents Devon's target allocation for its pension plan assets.

	December 31, 2015	December 31, 2014
Fixed income	70%	70%
Equity	20%	20%
Other	10%	10%

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

	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

	December 31, 2014				
			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%	$ 405	$ 50	$355	$—
Corporate bonds	32%	364	269	95	—
Other bonds	3%	30	30	—	—
Total fixed-income securities	70%	799	349	450	—
Equity securities:					
Global (large, mid, small cap)	17%	197	—	197	—
Other securities:					
Hedge fund and alternative investments	10%	112	—	—	112
Short-term investments	3%	41	15	26	—
Total other securities	13%	153	15	26	112
Total investments	100%	$1,149	$364	$673	$112

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, 2013	$ 112
Disbursements	(6)
Investment returns	6
December 31, 2014	112
Purchases	5
Investment returns	3
December 31, 2015	$ 120

Expected Cash Flows

The following table presents expected cash flow information for Devon's pension and postretirement benefit plans.

	Pension Benefits	Postretirement Benefits
	(Millions)	
Devon's 2016 contributions	$ 12	$3
Benefit payments:		
2016	$ 73	$3
2017	$ 75	$3
2018	$ 77	$3
2019	$ 78	$3
2020	$ 83	$2
2021 to 2025	$446	$7

Expected contributions included in the table above include amounts related to Devon's qualified plans, nonqualified plans and postretirement plans. Of the benefits expected to be paid in 2016, the $12 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.

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,		
	2015	2014	2013
		(Millions)	
401(k) and enhanced contribution plans	$63	$49	$41
Canadian pension and savings plans	16	20	26
Total	$79	$69	$67

16. 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 December 2015, Devon issued approximately 7 million shares of common stock as part of the Powder River Basin asset acquisition discussed in Note 2. Additionally, in January 2016, Devon issued approximately 23 million shares of common stock in conjunction with the STACK asset acquisition.

Dividends

Devon paid common stock dividends of \$396 million, \$386 million and \$348 million in 2015, 2014 and 2013, respectively. The quarterly cash dividend was \$0.20 per share in the first quarter of 2013. Devon increased the dividend rate to \$0.22 per share in the second quarter of 2013 and to \$0.24 per share in the second quarter of 2014.

Stock Option Proceeds

Devon received \$4 million, \$93 million and \$3 million from stock option proceeds in 2015, 2014 and 2013, respectively.

17. Noncontrolling Interests

Acquisition of Noncontrolling Interests

In March 2014, EnLink was formed as a publicly traded consolidated subsidiary of Devon to provide midstream services to Devon and third parties. Devon obtained approximately 120.5 million units, or a 52% ownership interest, as a result of this transaction. Approximately 92.7 million units were issued to the public for a 41% ownership interest, with the remaining 7% ownership interest held by the General Partner.

Subsidiary Equity Transactions

Through its equity distribution agreements, EnLink has the ability to sell common units through an "at the market" equity offering program. During 2015 and 2014, EnLink issued and sold approximately 1.3 million and 14.8 million common units through its at the market program and general public offerings, generating net proceeds of \$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, the Coronado acquisition and dropdown transactions discussed in Note 2, the ownership of EnLink at December 31, 2015 is approximately:

- 28% – Devon
- 27% – General Partner (controlled by Devon)
- 45% – Public unitholders

The net gains and losses and related income taxes resulting from these transactions have been recorded as an adjustment to equity, and the change in ownership reflected as an adjustment to noncontrolling interests.

As further discussed in Note 2, in January 2016, EnLink acquired midstream assets in exchange for cash and equity. Subsequent to this transaction, the ownership of the General Partner is approximately:

- 64% – Devon
- 36% – Public unitholders

Subsequent to this transaction, the ownership of EnLink is approximately:

- 25% – Devon
- 23% – General Partner (controlled by Devon)
- 52% – Public unitholders

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 $254 million and $135 million to non-Devon unitholders during 2015 and 2014, respectively.

18. 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 routine 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, 2015.

Year Ending December 31,	Purchase Obligations	Drilling and Facility Obligations	Operational Agreements	Office and Equipment Leases
		(Millions)		
2016	$ 557	$ 69	$ 994	$ 70
2017	703	51	972	58
2018	791	34	936	76
2019	803	5	402	68
2020	845	2	255	42
Thereafter	206	28	1,042	129
Total	$3,905	$189	$4,601	$443

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 $88 million, $64 million and $26 million in 2015, 2014 and 2013, respectively.

19. Fair Value Measurements

The following table provides carrying value and fair value measurement information for certain of Devon's financial assets and liabilities. 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, 2015 and December 31, 2014. Therefore, such financial assets and liabilities are not presented in the following table. Additionally, information regarding the fair values of oil and gas assets, goodwill and other intangible assets and pension plan assets is provided in Note 5, Note 12 and Note 15, respectively.

			Fair Value Measurements Using:		
	Carrying Amount	Total Fair Value	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(Millions)		
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	$(13,113)	$(11,927)	$ —	$(11,927)	$—
Capital lease obligations	$ (17)	$ (16)	$ —	$ (16)	$—
December 31, 2014 assets (liabilities):					
Cash equivalents	$ 950	$ 950	$ 340	$ 610	$—
Commodity derivatives	$ 1,995	$ 1,995	$ —	$ 1,995	$—
Commodity derivatives	$ (56)	$ (56)	$ —	$ (56)	$—
Interest rate derivatives	$ 1	$ 1	$ —	$ 1	$—
Interest rate derivatives	$ (1)	$ (1)	$ —	$ (1)	$—
Foreign currency derivatives	$ 8	$ 8	$ —	$ 8	$—
Debt	$(11,262)	$(12,472)	$ —	$(12,472)	$—
Capital lease obligations	$ (20)	$ (20)	$ —	$ (20)	$—

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 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.

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

20. 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 21.

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. For the reporting periods prior to the formation of EnLink, Devon has reclassified, from its U.S. segment to the EnLink segment, all asset-level amounts related to the midstream assets that it contributed to EnLink.

	U.S. (1)	Canada	EnLink (1)	Eliminations	Total
			(Millions)		
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
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	$ 14,600	$ 5,464	$ 9,565	$ (97)	$ 29,532
Capital expenditures	$ 4,575	$ 680	$ 978	$ —	$ 6,233
Year Ended December 31, 2014:					
Revenues from external customers	$ 14,854	$ 2,063	$ 2,649	$ —	$ 19,566
Intersegment revenues	$ —	$ —	$ 859	$ (859)	$ —
Depreciation, depletion and amortization	$ 2,475	$ 560	$ 284	$ —	$ 3,319
Asset impairments	$ 12	$ 1,941	$ —	$ —	$ 1,953
Gains and losses on asset sales	$ 5	$ (1,077)	$ —	$ —	$ (1,072)
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	$ 32,037	$ 8,517	$10,207	$ (124)	$ 50,637
Capital expenditures	$ 11,214	$ 1,344	$ 1,001	$ —	$ 13,559
Year Ended December 31, 2013:					
Revenues from external customers	$ 6,807	$ 2,656	$ 934	$ —	$ 10,397
Intersegment revenues	$ —	$ —	$ 1,362	$(1,362)	$ —
Depreciation, depletion and amortization	$ 1,744	$ 849	$ 187	$ —	$ 2,780
Asset impairments	$ 1,133	$ 843	$ —	$ —	$ 1,976
Interest expense	$ 392	$ 80	$ —	$ (35)	$ 437
Earnings (loss) before income taxes	$ 495	$ (532)	$ 186	$ —	$ 149
Income tax expense (benefit)	$ 258	$ (156)	$ 67	$ —	$ 169
Net earnings (loss)	$ 237	$ (376)	$ 119	$ —	$ (20)
Property and equipment, net	$ 18,201	$ 8,478	$ 1,768	$ —	$ 28,447
Total assets	$ 27,080	$13,560	$ 2,237	$ —	$ 42,877
Capital expenditures	$ 4,589	$ 1,841	$ 213	$ —	$ 6,643

(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.

21. 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, 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

	Year Ended December 31, 2013		
	U.S.	Canada	Total
		(Millions)	
Property acquisition costs:			
Proved properties	$ 19	$ 3	$ 22
Unproved properties	213	3	216
Exploration costs	443	152	595
Development costs	3,838	1,251	5,089
Costs incurred	$ 4,513	$1,409	$ 5,922

Costs incurred 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 $372 million, $376 million and $368 million in 2015, 2014 and 2013, 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 $54 million, $45 million and $42 million in 2015, 2014 and 2013, respectively.

Capitalized Costs

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

	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

	December 31, 2014		
	U.S.	Canada	Total
		(Millions)	
Proved properties	$ 59,849	$ 15,889	$ 75,738
Unproved properties	1,460	1,292	2,752
Total oil and gas properties	61,309	17,181	78,490
Accumulated DD&A	(38,213)	(11,347)	(49,560)
Net capitalized costs	$ 23,096	$ 5,834	$ 28,930

The following table presents a summary of Devon’s oil and gas properties not subject to amortization as of December 31, 2015.

	Costs Incurred In				
	2015	2014	2013	Prior to 2013	Total
			(Millions)		
Acquisition costs	$672	$412	$ 61	$510	$1,655
Exploration costs	191	132	69	170	562
Development costs	9	28	17	128	182
Capitalized interest	50	37	32	66	185
Total oil and gas properties not subject to amortization	$922	$609	$179	$874	$2,584

Included in the $2.6 billion of oil and gas properties not subject to amortization are approximately $1.9 billion of costs that Devon deems significant for individual assessment. These costs primarily relate to investments in the Pike thermal oil project in Canada and the newly acquired Powder River Basin assets. Devon anticipates determining its Pike development timeline in mid-2016, 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 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, 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)
Gain on sale of assets	—	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

	December 31, 2013		
	U.S.	Canada	Total
		(Millions)	
Oil, gas and NGL sales	$ 5,964	$ 2,558	$ 8,522
Lease operating expenses	(1,257)	(1,011)	(2,268)
General and administrative expenses	(125)	(77)	(202)
Production and property taxes	(380)	(59)	(439)
Depreciation, depletion and amortization	(1,640)	(825)	(2,465)
Asset impairments	(1,110)	(843)	(1,953)
Accretion of asset retirement obligations	(47)	(64)	(111)
Income tax benefit (expense)	(510)	88	(422)
Results of operations	$ 895	$ (233)	$ 662
Depreciation, depletion and amortization per Boe	$ 8.69	$ 12.87	$ 9.75

(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, 2012	205	65	270
Revisions due to prices	1	(1)	—
Revisions other than price	(18)	—	(18)
Extensions and discoveries	69	7	76
Purchase of reserves	1	—	1
Production	(28)	(15)	(43)
Sale of reserves	(1)	—	(1)
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
Proved developed reserves as of:			
December 31, 2012	166	62	228
December 31, 2013	194	56	250
December 31, 2014	255	23	278
December 31, 2015	203	22	225
Proved developed-producing reserves as of:			
December 31, 2012	155	56	211
December 31, 2013	178	51	229
December 31, 2014	224	19	243
December 31, 2015	192	19	211
Proved undeveloped reserves as of:			
December 31, 2012	39	3	42
December 31, 2013	35	—	35
December 31, 2014	96	—	96
December 31, 2015	39	—	39

	Bitumen (MMBbls)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2012	—	528	528
Revisions due to prices	—	(11)	(11)
Revisions other than price	—	16	16
Extensions and discoveries	—	38	38
Production	—	(19)	(19)
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
Proved developed reserves as of:			
December 31, 2012	—	99	99
December 31, 2013	—	111	111
December 31, 2014	—	137	137
December 31, 2015	—	219	219
Proved developed-producing reserves as of:			
December 31, 2012	—	99	99
December 31, 2013	—	111	111
December 31, 2014	—	137	137
December 31, 2015	—	219	219
Proved undeveloped reserves as of:			
December 31, 2012	—	429	429
December 31, 2013	—	441	441
December 31, 2014	—	384	384
December 31, 2015	—	301	301

	Gas (Bcf)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2012	8,762	684	9,446
Revisions due to prices	405	161	566
Revisions other than price	(299)	67	(232)
Extensions and discoveries	471	19	490
Purchase of reserves	1	—	1
Production	(709)	(165)	(874)
Sale of reserves	(81)	(8)	(89)
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
Proved developed reserves as of:			
December 31, 2012	7,391	679	8,070
December 31, 2013	7,707	752	8,459
December 31, 2014	6,948	36	6,984
December 31, 2015	5,694	13	5,707
Proved developed-producing reserves as of:			
December 31, 2012	7,091	624	7,715
December 31, 2013	7,425	680	8,105
December 31, 2014	6,746	34	6,780
December 31, 2015	5,546	13	5,559
Proved undeveloped reserves as of:			
December 31, 2012	1,371	5	1,376
December 31, 2013	843	6	849
December 31, 2014	703	—	703
December 31, 2015	114	—	114

	Natural Gas Liquids (MMBbls)		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2012	571	20	591
Revisions due to prices	8	3	11
Revisions other than price	(50)	3	(47)
Extensions and discoveries	64	1	65
Production	(41)	(4)	(45)
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
Proved developed reserves as of:			
December 31, 2012	431	20	451
December 31, 2013	468	23	491
December 31, 2014	486	—	486
December 31, 2015	411	—	411
Proved developed-producing reserves as of:			
December 31, 2012	406	19	425
December 31, 2013	442	21	463
December 31, 2014	467	—	467
December 31, 2015	393	—	393
Proved undeveloped reserves as of:			
December 31, 2012	140	—	140
December 31, 2013	84	—	84
December 31, 2014	92	—	92
December 31, 2015	17	—	17

	Total (MMBoe) [1]		
	U.S.	Canada	Total
Proved developed and undeveloped reserves:			
December 31, 2012	2,236	727	2,963
Revisions due to prices	76	18	94
Revisions other than price	(117)	29	(88)
Extensions and discoveries	212	49	261
Purchase of reserves	1	—	1
Production	(189)	(64)	(253)
Sale of reserves	(14)	(1)	(15)
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
Proved developed reserves as of:			
December 31, 2012	1,829	294	2,123
December 31, 2013	1,947	315	2,262
December 31, 2014	1,900	165	2,065
December 31, 2015	1,563	243	1,806
Proved developed-producing reserves as of:			
December 31, 2012	1,743	278	2,021
December 31, 2013	1,857	297	2,154
December 31, 2014	1,815	162	1,977
December 31, 2015	1,509	240	1,749
Proved undeveloped reserves as of:			
December 31, 2012	407	433	840
December 31, 2013	258	443	701
December 31, 2014	305	384	689
December 31, 2015	75	301	376

(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 2015 (MMBoe).

	U.S.	Canada	Total
Proved undeveloped reserves as of December 31, 2014	305	384	689
Extensions and discoveries	13	11	24
Revisions due to prices	(115)	80	(35)
Revisions other than price	(40)	(80)	(120)
Conversion to proved developed reserves	(88)	(94)	(182)
Proved undeveloped reserves as of December 31, 2015	75	301	376

Proved undeveloped reserves decreased 45% from year-end 2014 to year-end 2015, and the year-end 2015 balance represents 17% of total proved reserves. Drilling and development activities increased Devon's proved undeveloped reserves 24 MMBoe and resulted in the conversion of 182 MMBoe, or 26%, of the 2014 proved undeveloped reserves to proved developed reserves. Costs incurred to develop and convert Devon's proved undeveloped reserves were approximately $2.2 billion for 2015. Additionally, revisions other than price decreased Devon's proved undeveloped reserves 120 MMBoe primarily due to evaluations of certain properties in the U.S. and Canada. The largest revisions, which reduced reserves by 80 MMBoe, relate to evaluations of Jackfish bitumen reserves. Of the 40 MMBoe revisions recorded for U.S. properties, a reduction of approximately 27 MMBoe represents reserves that Devon now does not expect to develop in the next five years, including 20 MMBoe attributable to the Eagle Ford.

A significant amount of Devon's proved undeveloped reserves at the end of 2015 related to its Jackfish operations. At December 31, 2015 and 2014, Devon's Jackfish proved undeveloped reserves were 301 MMBoe and 384 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 to 2030. At the end of 2015, approximately 184 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 180 MMBoe of proved undeveloped reserves at Jackfish will require in excess of five years, from the date of this filing, to develop.

Price Revisions

2015 – Reserves decreased 302 MMBoe primarily due to lower commodity prices across all products. The lower bitumen price increased Canadian reserves due to the decline in royalties, which increases Devon's after-royalty volumes.

2014 – Reserves increased 9 MMBoe primarily due to higher gas prices in the Barnett Shale and the Anadarko Basin, partially offset by higher bitumen prices, which result in lower after-royalty volumes, in Canada.

2013 – Reserves increased 94 MMBoe primarily due to higher gas prices. Of this increase, 43 MMBoe related to the Barnett Shale and 19 MMBoe related to the Rocky Mountain area.

Revisions Other Than Price

Total revisions other than price for 2015 primarily related to evaluations of Eagle Ford and Jackfish. Negative revisions other than price at Jackfish are primarily due to a refined reserves methodology that resulted in a reduced recovery factor. Revisions other than price in 2014 and 2013 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

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.

2013 – Of the 261 MMBoe of extensions and discoveries, 76 MMBoe related to the Permian Basin, 54 MMBoe related to the Barnett Shale, 42 MMBoe related to the Anadarko Basin, 38 MMBoe related to Jackfish and 32 MMBoe related to the Mississippian-Woodford Trend.

The 2013 extensions and discoveries included 175 MMBoe related to additions from Devon's infill drilling activities, including 23 MMBoe at the Cana-Woodford Shale, 54 MMBoe at the Barnett Shale, 38 MMBoe at Jackfish, 33 MMBoe at the Permian Basin and 20 MMBoe at the Mississippian-Woodford Trend.

Purchase of Reserves

2015 – Of the 9 MMBoe of reserves purchases, 6 MMBoe 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

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

2014 – The total 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, 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

	Year Ended December 31, 2013		
	U.S.	Canada	Total
		(Millions)	
Future cash inflows	$ 61,983	$ 33,305	$ 95,288
Future costs:			
Development	(5,448)	(5,308)	(10,756)
Production	(26,663)	(15,709)	(42,372)
Future income tax expense	(9,046)	(2,327)	(11,373)
Future net cash flow	20,826	9,961	30,787
10% discount to reflect timing of cash flows	(10,346)	(4,700)	(15,046)
Standardized measure of discounted future net cash flows	$ 10,480	$ 5,261	$ 15,741

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 2015 estimates, Devon's future realized prices were assumed to be $44.33 per Bbl of oil, $23.84 per Bbl of bitumen, $2.06 per Mcf of gas and $10.11 per Bbl of NGLs. Of the $6.1 billion of future development costs as of the end of 2015, $0.6 billion, $0.6 billion and $0.4 billion are estimated to be spent in 2016, 2017 and 2018, respectively.

Future development costs include not only development costs but also future asset retirement costs. Included as part of the $6.1 billion of future development costs are $1.2 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,		
	2015	2014	2013
		(Millions)	
Beginning balance	$ 20,474	$15,741	$13,221
Net changes in prices and production costs	(20,756)	2,561	3,018
Oil, bitumen, gas and NGL sales, net of production costs	(2,704)	(6,865)	(5,613)
Changes in estimated future development costs	1,313	(768)	399
Extensions and discoveries, net of future development costs	1,129	4,836	4,047
Purchase of reserves	95	6,422	14
Sales of reserves in place	(79)	(2,384)	(44)
Revisions of quantity estimates	(1,451)	(746)	(1,040)
Previously estimated development costs incurred during the period	2,158	1,933	1,986
Accretion of discount	567	1,746	1,940
Foreign exchange and other	(1,254)	(107)	(583)
Net change in income taxes	7,196	(1,895)	(1,604)
Ending balance	$ 6,688	$20,474	$15,741

22. Supplemental Quarterly Financial Information (Unaudited)

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

	2015				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(Millions, except per share amounts)				
Operating revenues	$ 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)

	2014				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(Millions, except per share amounts)				
Operating revenues	$ 3,725	$ 4,510	$ 5,336	$ 5,995	$ 19,566
Earnings before income taxes	$ 560	$ 1,554	$ 1,654	$ 291	$ 4,059
Net earnings (loss) attributable to Devon	$ 324	$ 675	$ 1,016	$ (408)	$ 1,607
Basic net earnings (loss) per share attributable to Devon	$ 0.80	$ 1.65	$ 2.48	$ (1.01)	$ 3.93
Diluted net earnings (loss) per share attributable to Devon	$ 0.79	$ 1.64	$ 2.47	$ (1.01)	$ 3.91

Net Earnings (Loss) Attributable to Devon

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 ($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.

The fourth quarter of 2014 includes asset impairments of $1.9 billion (or $4.79 per diluted share) 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, 2015 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 17, 2016, management concluded that its internal control over financial reporting was effective as of December 31, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015 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, 2015, 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 2015 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 not later than April 29, 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 not later than April 29, 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 not later than April 29, 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 not later than April 29, 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 not later than April 29, 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 June 11, 2015, by and among Registrant and Goldman, Sachs & Co. and J.P. Morgan Securities LLC, as representatives of the several underwriters named therein (incorporated by reference to Exhibit 1.1 to Registrant's Form 8-K filed June 16, 2015; File No. 001-32318).
1.2	Underwriting Agreement dated December 10, 2015, by and among Registrant and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC, as representatives of the several underwriters named therein (incorporated by reference to Exhibit 1.1 to Registrant's Form 8-K filed December 15, 2015; 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 10-K for the fiscal year ending December 31, 2012; 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.

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.
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 Floating Rate Senior Notes due 2016 and 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 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 Corporation, L.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 as filed October 31, 2001; File No. 333-68694).
4.13	Indenture dated as of July 8, 1998 among Devon OEI Operating, L.L.C. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 10.24 to the Form 10-Q for the period ended June 30, 1998 of Ocean Energy, Inc.; File No. 001-14252).

Exhibit No.	Description
4.14	First Supplemental Indenture, dated March 30, 1999 to Indenture dated as of July 8, 1998 among Devon OEI Operating, L.L.C. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, 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 for the period ended March 31, 1999; File No. 001-08094).
4.15	Second Supplemental Indenture, dated as of May 9, 2001 to Indenture dated as of July 8, 1998 among Devon OEI Operating, L.L.C. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, 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 among Devon OEI Operating, L.L.C., as Issuer, Devon Energy Production Company, L.P., as Successor Guarantor, and Wells Fargo Bank Minnesota, 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 for the year ended December 31, 2005; File No. 001-32318).
4.17	Senior Indenture dated September 1, 1997, among Devon OEI Operating, L.L.C. (as successor by merger to Ocean Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as Trustee, and Specimen of 7.50% Senior Notes (incorporated by reference to Exhibit 4.4 to Ocean Energy Inc.'s Form 10-K for the year ended December 31, 1997; File No. 001-08094).
4.18	First Supplemental Indenture, dated as of March 30, 1999 to Senior Indenture dated as of September 1, 1997, among Devon OEI Operating, L.L.C. (as successor by merger to Ocean Energy, Inc.) 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's Form 10-Q for the period ended March 31, 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, among Devon OEI Operating, L.L.C. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, 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, 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 for the year ended December 31, 2005; File No. 001-32318).
4.21	Registrant has not filed instruments defining the rights of holders of long-term indebtedness of Registrant's majority owned subsidiary, EnLink Midstream Partners, LP, as none of which exceeds ten percent of the total assets of Registrant and its subsidiaries on a consolidated basis. Registrant hereby agrees to furnish a copy of any such agreements to the Commission upon request.
10.1	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 October 29, 2012; File No. 001-32318).

Exhibit No.	Description
10.2	Extension Agreement dated 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 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 99.1 to Registrant's Form S-8 filed June 18, 2012; File No. 333-182198).*
10.7	Devon Energy Corporation 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 Exhibit 4.8 to Registrant's Form S-8 filed August 17, 2005; File No. 333-127630).*
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 on April 28, 2006; File No. 001-32318).*
10.10	Devon Energy Corporation 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).*
10.12	Devon Energy Corporation 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	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).*

Exhibit No.	Description
10.14	Devon Energy Corporation 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).*
10.15	Devon Energy Corporation 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).*
10.16	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).*
10.17	Devon Energy Corporation 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).*
10.18	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).*
10.19	Devon Energy Corporation 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).*
10.20	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).*
10.21	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).*
10.22	Devon Energy Corporation 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).*
10.23	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).*
10.24	Devon Energy Corporation 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).*
10.25	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).*
10.26	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).*
10.27	Form of Employment Agreement between Registrant and certain executive officers (Amended and Restated Form of Employment Agreement dated December 15, 2008 (Exhibit 10.22 above), as amended by Amendment No. 1 thereto dated April 19, 2011 (Exhibit 10.23 above)) (incorporated by reference to Exhibit 10.22 to Registrant's Form 10-K filed February 28, 2014; File No. 001-32318).*

Exhibit No.	Description
10.28	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 10.16 to Registrant's Form 10-K filed February 21, 2013; File No. 001-32318).*
10.29	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).*
10.30	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).*
10.31	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).*
10.32	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 10.17 to Registrant's Form 10-K filed February 21, 2013; File No. 001-32318).*
10.33	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).*
10.34	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).*
10.35	Form of Incentive Stock Option 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).*
10.36	Form of Employee Nonqualified Stock Option 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).*
10.37	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).*

Exhibit No.	Description
10.38	Form of Restricted Stock 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).*
10.39	Form of Notice of Grant of Restricted Stock Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and all non-management directors for restricted stock awards (incorporated by reference to Exhibit 10.33 to Registrant's Form 10-K filed February 28, 2014; File No. 001-32318).*
10.40	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, 2014; File No. 001-32318).*
10.41	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).*
10.42	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).*
10.43	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.*
10.44	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.*
12	Statement of computations of ratios of earnings to fixed charges.
21	Registrant's Significant Subsidiaries.
23.1	Consent of KPMG LLP.
23.2	Consent of LaRoche Petroleum Consultants, Ltd.
23.3	Consent of Deloitte.
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.

* Compensatory plans or arrangements

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/ DAVID A. HAGER
David A. Hager
President and Chief Executive Officer

February 17, 2016

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 and Chief Executive Officer (Principal executive officer)	February 17, 2016
/s/ THOMAS L. MITCHELL Thomas L. Mitchell	Executive Vice President and Chief Financial Officer (Principal financial officer)	February 17, 2016
/s/ JEREMY D. HUMPHERS Jeremy D. Humphers	Senior Vice President and Chief Accounting Officer (Principal accounting officer)	February 17, 2016
/s/ J. LARRY NICHOLS J. Larry Nichols	Executive Chairman of the Board	February 17, 2016
/s/ JOHN RICHELS John Richels	Vice Chairman of the Board	February 17, 2016
/s/ BARBARA M. BAUMANN Barbara M. Baumann	Director	February 17, 2016
/s/ JOHN E. BETHANCOURT John E. Bethancourt	Director	February 17, 2016
/s/ ROBERT H. HENRY Robert H. Henry	Director	February 17, 2016
/s/ MICHAEL M. KANOVSKY Michael M. Kanovsky	Director	February 17, 2016
/s/ ROBERT A. MOSBACHER, JR. Robert A. Mosbacher, Jr.	Director	February 17, 2016
/s/ DUANE C. RADTKE Duane C. Radtke	Director	February 17, 2016
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	February 17, 2016

Directors

J. Larry Nichols
Executive Chairman

John Richels
Vice Chairman

Barbara M. Baumann (1) (3)

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

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 Vaughn
Chief Operating Officer

Thomas L. Mitchell
Executive Vice President and Chief Financial Officer

R. Alan Marcum
Executive Vice President, Administration

Frank W. Rudolph
Executive Vice President, Human Resources

Darryl G. Smette
Executive Vice President, Marketing, Facilities, Pipeline and Supply Chain

Lyndon C. Taylor
Executive Vice President and General Counsel

Other Executives

Sue Alberti
Senior Vice President, Marketing, Supply Chain and Evaluation & Planning

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 and Treasurer

Michael J. Stover
Senior Vice President, Strategic Services

Howard J. Thill
Senior Vice President, Communications and Investor Relations

Other Information

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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 8, 2016, 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 8,500 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 four of this report.

Devon Energy Corporation
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