PIONEER NATURAL RESOURCES CO
Form 10-Q
August 07, 2015

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

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2015
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ________ to ________
Commission File Number: 1-13245

PIONEER NATURAL RESOURCES COMPANY
(Exact name of Registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	75-2702753 (I.R.S. Employer Identification No.)
5205 N. O'Connor Blvd., Suite 200, Irving, Texas (Address of principal executive offices)	75039 (Zip Code)

(972) 444-9001
(Registrant's telephone number, including area code)
Not applicable
(Former name, former address and former fiscal year, if changed since last report)

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 ý 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 ý No ¨
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	ý	Accelerated filer	¨
Non-accelerated filer	o (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

Number of shares of Common Stock outstanding as of August 4	149,307,983

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Cautionary Statement Concerning Forward-Looking Statements

The information in this Quarterly Report on Form 10-Q (this "Report") contains forward-looking statements that involve risks and uncertainties. When used in this document, the words "believes," "plans," "expects," "anticipates," "forecasts," "intends," "continue," "may," "will," "could," "should," "future," "potential," "estimate" or the negative of such terms and similar expressions as they relate to Pioneer Natural Resources Company ("Pioneer" or the "Company") are intended to identify forward-looking statements, which are generally not historical in nature. The forward-looking statements are based on the Company's current expectations, assumptions, estimates and projections about the Company and the industry in which the Company operates. Although the Company believes that the expectations and assumptions reflected in the forward-looking statements are reasonable as and when made, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond the Company's control. These risks and uncertainties include, among other things, volatility of commodity prices, product supply and demand, competition, the ability to obtain environmental and other permits and the timing thereof, other government regulation or action, the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms, litigation, the costs and results of drilling and operations, availability of equipment, services, resources and personnel required to perform the Company's drilling and operating activities, access to and availability of transportation, processing, fractionation and refining facilities, Pioneer's ability to replace reserves, implement its business plans or complete its development activities as scheduled, access to and cost of capital, the financial strength of counterparties to Pioneer's credit facility and derivative contracts and the purchasers of Pioneer's oil, NGL and gas production, uncertainties about estimates of reserves and the ability to add proved reserves in the future, the assumptions underlying production forecasts, quality of technical data, environmental and weather risks, including the possible impacts of climate change, the risks associated with the ownership and operation of the Company's industrial sand mining and oilfield services businesses, and acts of war or terrorism. These and other risks are described in the Company's Annual Report on Form 10-K, this and other Quarterly Reports on Form 10-Q and other filings with the United States Securities and Exchange Commission. In addition, the Company may be subject to currently unforeseen risks that may have a materially adverse effect on it. Accordingly, no assurances can be given that the actual events and results will not be materially different than the anticipated results described in the forward-looking statements. See "Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations," "Part 1, Item 3. Quantitative and Qualitative Disclosures About Market Risk" and "Part II, Item 1A. Risk Factors" in this Report and "Part I, Item 1. Business — Competition, Markets and Regulations," "Part I, Item 1A. Risk Factors," "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk" in the Company's Annual Report on Form 10-K for the year ended December 31, 2014 for a description of various factors that could materially affect the ability of Pioneer to achieve the anticipated results described in the forward-looking statements. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. The Company undertakes no duty to publicly update these statements except as required by law.

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Definitions of Certain Terms and Conventions Used Herein

Within this Report, the following terms and conventions have specific meanings:

- "Bbl" means a standard barrel containing 42 United States gallons.
- "BOE" means a barrel of oil equivalent and is a standard convention used to express oil and gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of six thousand cubic feet of gas to one Bbl of oil or natural gas liquid.
- "BOEPD" means BOE per day.
- "Btu" means British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- "Conway" means the daily average natural gas liquids components as priced in Oil Price Information Service ("OPIS") in the table "U.S. and Canada LP – Gas Weekly Averages" at Conway, Kansas.
- "DD&A" means depletion, depreciation and amortization.
- "GAAP" means accounting principles that are generally accepted in the United States of America.
- "LIBOR" means London Interbank Offered Rate, which is a market rate of interest.
- "Mcf" means one thousand cubic feet and is a measure of gas volume.
- "MMBtu" means one million Btus.
- "Mont Belvieu" means the daily average natural gas liquids components as priced in OPIS in the table "U.S. and Canada LP – Gas Weekly Averages" at Mont Belvieu, Texas.
- "NGL" means natural gas liquid.
- "NYMEX" means the New York Mercantile Exchange.
- "Pioneer" or the "Company" means Pioneer Natural Resources Company and its subsidiaries.
- "Proved reserves" mean the quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

- "U.S." means United States.
- With respect to information on the working interest in wells, drilling locations and acreage, "net" wells, drilling locations and acres are determined by multiplying "gross" wells, drilling locations and acres by the Company's working interest in such wells, drilling locations or acres. Unless otherwise specified, wells, drilling locations and acreage statistics quoted herein represent gross wells, drilling locations or acres.
- Unless otherwise indicated, all currency amounts are expressed in U.S. dollars.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements
PIONEER NATURAL RESOURCES COMPANY
CONSOLIDATED BALANCE SHEETS
(in millions)

	June 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$219	$1,025
Accounts receivable:		
Trade, net	388	436
Due from affiliates	2	4
Income taxes receivable	22	23
Inventories	269	241
Prepaid expenses	16	15
Derivatives	354	578
Other	35	37
Total current assets	1,305	2,359
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	16,375	15,662
Unproved properties	164	159
Accumulated depletion, depreciation and amortization	(6,044)	(5,431)
Total property, plant and equipment	10,495	10,390
Goodwill	272	272
Other property and equipment, net	1,466	1,391
Investment in unconsolidated affiliate	277	239
Derivatives	89	181
Other, net	98	94
	$14,002	$14,926

The financial information included as of June 30, 2015 has been prepared by management without audit by independent registered public accountants.
The accompanying notes are an integral part of these consolidated financial statements.

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PIONEER NATURAL RESOURCES COMPANY
CONSOLIDATED BALANCE SHEETS (continued)
(in millions)

	June 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$771	$1,197
Due to affiliates	58	123
Interest payable	62	40
Income taxes payable	—	1
Deferred income taxes	81	161
Derivatives	—	3
Other	61	55
Total current liabilities	1,033	1,580
Long-term debt	2,672	2,665
Derivatives	1	2
Deferred income taxes	1,714	1,803
Other liabilities	274	287
Equity:		
Common stock, $.01 par value; 500 million shares authorized; 152 million shares issued as of June 30, 2015 and December 31, 2014, respectively	2	2
Additional paid-in capital	6,220	6,167
Treasury stock at cost: 3 million shares as of June 30, 2015 and December 31, 2014, respectively	(202)	(171)
Retained earnings	2,281	2,583
Total equity attributable to common stockholders	8,301	8,581
Noncontrolling interests in consolidating subsidiaries	7	8
Total equity	8,308	8,589
Commitments and contingencies		
	$14,002	$14,926

The financial information included as of June 30, 2015 has been prepared by management without audit by independent registered public accountants.
The accompanying notes are an integral part of these consolidated financial statements.

PIONEER NATURAL RESOURCES COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per share data)
(Unaudited)

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Revenues and other income:				
Oil and gas	$596	$938	$1,113	$1,828
Sales of purchased oil and gas	236	205	339	353
Interest and other	11	3	17	7
Derivative gains (losses), net	(197)	(218)	44	(322)
Gain on disposition of assets, net	2	4	3	10
	648	932	1,516	1,876
Costs and expenses:				
Oil and gas production	163	167	343	325
Production and ad valorem taxes	37	56	76	111
Depletion, depreciation and amortization	329	243	639	460
Purchased oil and gas	237	198	345	341
Impairment of oil and gas properties	—	—	138	—
Exploration and abandonments	28	28	54	59
General and administrative	83	82	165	163
Accretion of discount on asset retirement obligations	3	3	6	6
Interest	46	47	92	92
Other	62	21	110	36
	988	845	1,968	1,593
Income (loss) from continuing operations before income taxes	(340)	87	(452)	283
Income tax benefit (provision)	123	(32)	160	(83)
Income (loss) from continuing operations	(217)	55	(292)	200
Loss from discontinued operations, net of tax	(1)	(54)	(4)	(76)
Net income (loss) attributable to common stockholders	$(218)	$1	$(296)	$124
Basic and diluted earnings per share attributable to common stockholders:				
Income (loss) from continuing operations	$(1.45)	$0.38	$(1.95)	$1.38
Loss from discontinued operations	(0.01)	(0.37)	(0.03)	(0.52)
Net income (loss)	$(1.46)	$0.01	$(1.98)	$0.86
Basic and diluted weighted average shares outstanding	149	143	149	143
Dividends declared per share	$—	$—	$0.04	$0.04

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PIONEER NATURAL RESOURCES COMPANY
CONSOLIDATED STATEMENT OF EQUITY
(in millions, except dividends per share)
(Unaudited)

	Equity Attributable To Common Stockholders						
	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Noncontrolling Interests	Total Equity
Balance as of December 31, 2014	149	$2	$ 6,167	$(171)	$2,583	$ 8	$8,589
Dividends declared ($0.04 per share)	—	—	—	—	(6)	—	(6)
Purchases of treasury stock	—	—	—	(31)	—	—	(31)
Tax benefits related to stock-based compensation	—	—	6	—	—	—	6
Compensation costs included in net income	—	—	47	—	—	—	47
Cash distributions to noncontrolling interests	—	—	—	—	—	(1)	(1)
Net loss	—	—	—	—	(296)	—	(296)
Balance as of June 30, 2015	149	$2	$ 6,220	$(202)	$2,281	$ 7	$8,308

The financial information included herein has been prepared by management
without audit by independent registered public accountants.
The accompanying notes are an integral part of these consolidated financial statements.

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PIONEER NATURAL RESOURCES COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)
(Unaudited)

	Six Months Ended June 30, 2015	2014
Cash flows from operating activities:		
Net income (loss)	$(296)	$124
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation and amortization	639	460
Impairment of oil and gas properties	138	—
Impairment of inventory and other property and equipment	9	4
Exploration expenses, including dry holes	15	10
Deferred income taxes	(161)	65
Gain on disposition of assets, net	(3)	(10)
Accretion of discount on asset retirement obligations	6	6
Discontinued operations	(3)	179
Interest expense	9	9
Derivative related activity	312	298
Amortization of stock-based compensation	47	43
Other	(6)	28
Change in operating assets and liabilities:		
Accounts receivable, net	49	(59)
Income taxes receivable	1	(2)
Inventories	(44)	(8)
Prepaid expenses	(1)	2
Other current assets	(8)	(4)
Accounts payable	(275)	30
Interest payable	22	—
Income taxes payable	(1)	1
Other current liabilities	(17)	7
Net cash provided by operating activities	432	1,183
Cash flows from investing activities:		
Proceeds from disposition of assets, net of cash sold	7	369
Additions to oil and gas properties	(1,083)	(1,362)
Additions to other assets and other property and equipment, net	(130)	(110)
Net cash used in investing activities	(1,206)	(1,103)
Cash flows from financing activities:		
Borrowings under long-term debt	—	325
Principal payments on long-term debt	—	(325)
Distributions to noncontrolling interests	(1)	—
Exercise of long-term incentive plan stock options	—	7
Purchases of treasury stock	(31)	(33)
Tax benefits related to stock-based compensation	6	4
Dividends paid	(6)	(6)
Net cash used in financing activities	(32)	(28)
Net increase (decrease) in cash and cash equivalents	(806)	52
Cash and cash equivalents, beginning of period	1,025	393

Cash and cash equivalents, end of period	$219	$445

The financial information included herein has been prepared by management without audit by independent registered public accountants.

The accompanying notes are an integral part of these consolidated financial statements.

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PIONEER NATURAL RESOURCES COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2015
(Unaudited)

NOTE A. Organization and Nature of Operations
Pioneer Natural Resources Company ("Pioneer" or the "Company") is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. The Company is a large independent oil and gas exploration and production company operating in the United States, with operations primarily in the Permian Basin in West Texas, the Eagle Ford Shale play in South Texas, the Raton field in southeastern Colorado and the West Panhandle field in the Texas Panhandle.
NOTE B. Basis of Presentation
Presentation. In the opinion of management, the consolidated financial statements of the Company as of June 30, 2015 and for the three and six months ended June 30, 2015 and 2014 include all adjustments and accruals, consisting only of normal, recurring accrual adjustments, which are necessary for a fair presentation of the results for the interim periods. These interim results are not necessarily indicative of results for a full year.
Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles in the United States ("GAAP") have been condensed in or omitted from this report pursuant to the rules and regulations of the United States Securities and Exchange Commission (the "SEC"). These consolidated financial statements should be read together with the consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2014.
Certain reclassifications have been made to the 2014 financial statement and footnote amounts in order to conform to the 2015 presentation.
Restructuring. On May 4, 2015, the Company announced plans to restructure its operations in Colorado, including closing its office in Denver, Colorado and eliminating its Trinidad-based pumping services operations. The Company is also relocating a number of employees from Denver to its corporate headquarters in Irving, Texas. This initiative is expected to be substantially completed by the end of the third quarter of 2015.
In connection therewith, during the three and six months ended June 30, 2015, the Company recognized $15 million of restructuring charges in other expense in the accompanying consolidated statement of operations. The Company estimates that it will incur an additional $10 million of restructuring charges during the third quarter of 2015. The aggregate $25 million estimate of restructuring charges includes approximately $16 million in employee severance costs, $6 million in lease-related costs and $3 million in employee relocation and other costs.
Employee severance costs. The $16 million of estimated employee severance costs is based on the number of employees that are expected to be impacted by the restructuring. Approximately $15 million is related to cash severance and $1 million is related to accelerated vesting of share-based grants, which are noncash charges.
Lease obligations and other. The $6 million of lease-related costs relates to certain Denver office space that will no longer be used as a part of the restructuring. Approximately $2 million represents the impairment of leasehold improvements and approximately $4 million represents the Company’s future obligations under the operating leases, net of anticipated sublease income.
As of June 30, 2015, the Company’s had $12 million of restructuring liabilities related to employee severance costs recorded in other current liabilities.
New accounting pronouncements. In July 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-11, "Inventory (Topic 330): Simplifying the Measurement of Inventory." ASU 2015-11 requires an entity to measure inventory at the lower of cost and net realizable value rather than lower of cost or market as previously required by GAAP. ASU 2015-11 is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. This update should be applied prospectively with early application permitted. The Company is currently evaluating the new guidance and has not determined the impact this standard may have on its financial statements.

In April 2015, the FASB issued ASU 2015-03, "Interest-Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs." ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts.

Currently, debt issuance costs are recognized as deferred charges and recorded as assets. The guidance is effective for annual and interim periods beginning after December 15, 2015 with early adoption permitted and is to be implemented retrospectively. Adoption of the new guidance will only affect the presentation of the Company's consolidated balance sheets and will not have a material impact.

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)," which supersedes the revenue recognition requirements in Accounting Standards Codification ("ASC") Topic 605, "Revenue Recognition," and most industry-specific guidance. ASU 2014-09 is based on the principle that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. ASU 2014-09 applies to all contracts with customers except those that are within the scope of other topics in the FASB ASC. The new guidance is effective for annual reporting periods beginning after December 15, 2016 for public companies, with early adoption not permitted. Entities have the option of using either a full retrospective or modified approach to adopt ASU 2014-09. In April 2015, the FASB issued an exposure draft proposing to defer the effective date until annual reports beginning after December 15, 2017. In July 2015, the FASB voted to approve the deferral, although a final ASU has not yet been issued. The Company is currently evaluating the new guidance and has not determined the impact this standard may have on its financial statements or decided upon the method of adoption.

NOTE C. Divestitures

Divestitures Recorded in Continuing Operations

For the three and six months ended June 30, 2015, the Company recorded net gains on disposition of assets in continuing operations of $2 million and $3 million, respectively, as compared to $4 million and $10 million for the same respective periods in 2014. The net gains attributable to the disposition of assets included the following:

- Vertical drilling rigs. In March 2014, the Company completed the sale of Sendero Drilling Company, LLC ("Sendero") to Sendero's minority interest owner for cash proceeds of $31 million, which resulted in a gain of $1 million. As part of the sales agreement, the Company committed to a lease agreement with Sendero for 12 vertical rigs through December 31, 2015, and eight vertical rigs in 2016. During the three and six months ended June 30, 2015, the Company incurred $10 million and $20 million of idle drilling rig fees related to the leased Sendero rigs.

- Permian Basin. During February 2014, the Company completed the sale of proved and unproved properties in Gaines and Dawson counties in the Spraberry field in West Texas for cash proceeds of $72 million, which resulted in a gain of $2 million.

Divestitures Recorded as Discontinued Operations

During 2014, the Company completed the sales of its (i) net assets in the Hugoton field in southwest Kansas for cash proceeds of $328 million, (ii) net assets in the Barnett Shale field in North Texas for cash proceeds of $150 million and (iii) capital stock in its Alaskan subsidiary ("Pioneer Alaska") for cash proceeds of $267 million. The Company has classified its Hugoton, Barnett Shale and Pioneer Alaska results of operations as loss from discontinued operations, net of tax, in the accompanying consolidated statements of operations.

The following table represents the components of the Company's discontinued operations for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Revenues and other income (a)	$—	$66	$—	$184
Costs and expenses (b)	(1)	(148)	(6)	(300)
Loss from discontinued operations before income taxes	(1)	(82)	(6)	(116)
Current tax provision	—	—	—	(1)
Deferred tax benefit	—	28	2	41
Loss from discontinued operations	$(1)	$(54)	$(4)	$(76)

(a) Primarily reflects oil and gas revenues and cash received associated with Alaskan Petroleum Production Tax credits on qualifying capital expenditures.

(b) Costs and expenses during 2015 were primarily related to an arbitration award associated with plugging and abandonment obligations for two Gulf of Mexico wells from which Pioneer withdrew in 2009. Costs and expenses in 2014 were primarily comprised of oil and gas production costs and impairment charges. See Note D for information about impairment charges on the Barnett Shale assets and Pioneer Alaska.

NOTE D. Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are based upon inputs that market participants use in pricing an asset or liability, which are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. The three input levels of the fair value hierarchy are as follows:

- Level 1 – quoted prices for identical assets or liabilities in active markets.
- Level 2 – quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability (e.g., interest rates) and inputs derived principally from or corroborated by observable market data by correlation or other means.
- Level 3 – unobservable inputs for the asset or liability.

Assets and liabilities measured at fair value on a recurring basis. The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement in its entirety.

The following table presents the Company's assets and liabilities that are measured at fair value on a recurring basis as of June 30, 2015 for each of the fair value hierarchy levels:

	Fair Value Measurement at June 30, 2015 Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value at June 30, 2015
	(in millions)			
Assets:				
Commodity derivatives	$—	$443	$ —	$443
Deferred compensation plan assets	73	—	—	73
Total assets	73	443	—	516
Liabilities:				
Commodity derivatives	—	1	—	1
Total liabilities	—	1	—	1
Total recurring fair value measurements	$73	$442	$ —	$515

Commodity derivatives. The Company's commodity derivatives represent oil, natural gas liquids ("NGL") and gas swap contracts and collar contracts with short puts. The asset and liability measurements for the Company's commodity derivative contracts represent Level 2 inputs in the hierarchy. The Company utilizes discounted cash flow and option-pricing models for valuing its commodity derivatives.

The asset and liability values attributable to the Company's commodity derivatives were determined based on inputs that include (i) the contracted notional volumes, (ii) independent active market price quotes, (iii) the applicable estimated credit-adjusted risk-free rate yield curve and (iv) the implied rate of volatility inherent in the collar contracts with short puts, which is based on active and independent market-quoted volatility factors.

Deferred compensation plan assets. The Company's deferred compensation plan assets represent investments in equity and mutual fund securities that are actively traded on major exchanges. These investments are measured based on observable prices on major exchanges. As of June 30, 2015, the significant inputs to these asset values represented Level 1 independent active exchange market price inputs.

Assets and liabilities measured at fair value on a nonrecurring basis. Certain assets and liabilities are measured at fair value on a nonrecurring basis. These assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances. These assets and liabilities can include inventory, proved and unproved oil and gas properties and other long-lived assets that are written down to fair value when they are impaired or held for sale. During the three and six months ended June 30, 2015, the Company recorded charges in other expense in the Company's accompanying consolidated statements of operations of $3 million and $9 million to reduce the carrying value of inventory to fair value.

Proved oil and gas properties. During the three months ended March 31, 2015, reductions in management's longer-term commodity price outlooks ("Management's Price Outlooks") provided indications of possible impairment of the Company's oil and gas properties in the West Panhandle field. As a result of management's assessments, during the first quarter of 2015, the Company recognized a pretax noncash impairment charge of $138 million to reduce the carrying value of the West Panhandle field to its estimated fair value.

The Company calculated the fair value of the West Panhandle field as of March 31, 2015 using a discounted future cash flow model. Significant Level 3 assumptions associated with the calculation of the West Panhandle field's discounted future cash flows as of March 31, 2015 included Management's Price Outlooks for (i) oil prices of $65.02 per barrel ("Bbl") and (ii) gas prices of $3.83 per million British thermal units ("MMBtu") and management's outlooks for (iii) production costs, (iv) capital expenditures, (v) production and (vi) estimated proved reserves and risk-adjusted probable reserves. Management's Price Outlooks are developed based on third-party futures price outlooks as of the measurement date. The expected future net cash flows were discounted using an annual rate of 10 percent to determine estimated fair value.

Assets associated with divestitures. Long-lived assets that are classified as held for sale are recorded at the lower of the asset's net carrying amount or estimated fair value less costs to sell. The Barnett Shale field assets and Pioneer Alaska were classified as held for sale at December 31, 2013 and carried as such until their divestitures in September 2014 and April 2014, respectively. Associated therewith, during the three and six months ended June 30, 2014, the Company recognized impairment charges of $114 million and $128 million, respectively, to reduce the carrying value of the Barnett Shale field assets to their estimated fair value, less costs to sell, at June 30, 2014, and during the three months ended March 31, 2014, the Company recognized impairment charges of $97 million to reduce the carrying value of Pioneer Alaska to its estimated fair value, less costs to sell, at March 31, 2014.

See Note C for additional information regarding the Company's divestitures of the Barnett Shale field assets and Pioneer Alaska.

Financial instruments not carried at fair value. Carrying values and fair values of financial instruments that are not carried at fair value in the consolidated balance sheets as of June 30, 2015 and December 31, 2014 are as follows:

	June 30, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in millions)			
Long-term debt	$2,672	$2,949	$2,665	$2,938

Long-term debt includes the Company's credit facility and the Company's senior notes. The fair value of debt is determined utilizing inputs that are Level 2 measurements in the fair value hierarchy.

Credit facility. The fair value of the Company's credit facility is calculated using a discounted cash flow model based on (i) forecasted contractual interest and fee payments, (ii) forward active market-quoted United States Treasury Bill rates and (iii) the applicable credit-adjustments.

Senior notes. The Company's senior notes represent debt securities that are traded on major exchanges but are not actively traded. The fair values of the Company's senior notes are based on their periodic values as quoted on the major exchanges.

The Company has other financial instruments consisting primarily of cash equivalents, receivables, prepaid expenses, payables and other current assets and liabilities that approximate fair value due to the nature of the instrument and their relatively short maturities. Non-financial assets and liabilities initially measured at fair value include assets acquired and liabilities assumed in a business combination, goodwill and asset retirement obligations.

NOTE E. Derivative Financial Instruments

The Company utilizes commodity swap contracts, collar contracts and collar contracts with short puts to (i) reduce the effect of price volatility on the commodities the Company produces and sells or consumes, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. The Company also, from time to time, utilizes interest rate contracts to reduce the effect of interest rate volatility on the Company's indebtedness.

Oil production derivative activities. All material physical sales contracts governing the Company's oil production are tied directly to, or are highly correlated with, New York Mercantile Exchange ("NYMEX") West Texas Intermediate ("WTI") oil prices. The Company uses derivative contracts to manage oil price volatility and basis swap contracts to reduce basis risk between NYMEX prices and the actual index prices at which the oil is sold.

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The following table sets forth the volumes per day associated with the Company's outstanding oil derivative contracts as of June 30, 2015 and the weighted average oil prices for those contracts:

	Six Months Ending December 31,	Year Ending December 31,	
	2015	2016	2017
Swap contracts:			
Volume (Bbl)	82,000	—	—
Price per Bbl	$71.18	$—	$—
Collar contracts with short puts:			
Volume (Bbl) (a)	15,000	100,514	15,000
Price per Bbl:			
Ceiling	$97.69	$77.21	$73.01
Floor	$82.97	$66.92	$65.00
Short put	$69.67	$47.58	$55.00
Rollfactor swap contracts:			
Volume (Bbl)	37,000	—	—
NYMEX roll price (b)	$0.06	$—	$—

(a) Counterparties have the option to extend for an additional year 5,000 Bbls per day of 2015 collar contracts with short puts with a ceiling price of $100.08 per Bbl, a floor price of $90.00 per Bbl and a short put price of $80.00 per Bbl. The option to extend is exercisable on December 31, 2015. These contracts give the counterparties the option to extend the contracts under the same terms for an additional year if the option to extend is exercised by the counterparties on December 31, 2015.

(b) Represents swaps that fix the difference between (i) each day's price per Bbl of WTI for the first nearby month less (ii) the price per Bbl of WTI for the second nearby NYMEX month, multiplied by .6667; plus (iii) each day's price per Bbl of WTI for the first nearby month less (iv) the price per Bbl of WTI for the third nearby NYMEX month, multiplied by .3333.

NGL production derivative activities. All material physical sales contracts governing the Company's NGL production are tied directly or indirectly to either Mont Belvieu or Conway fractionation facilities' NGL component product prices.

The following table sets forth the volumes per day associated with the Company's outstanding NGL derivative contracts as of June 30, 2015 and the weighted average NGL prices for those contracts:

	Six Months Ending December 31, 2015	Year Ending December 31, 2016
Ethane swap contracts:		
Volume (Bbl) (a)	6,000	4,000
Price per Bbl	$7.80	$12.29
Propane swap contracts:		
Volume (Bbl) (a)	11,000	4,500
Price per Bbl	$21.62	$22.12

(a) Subsequent to June 30, 2015, the Company entered into an additional (i) 1,000 Bbls per day of swap contracts for ethane forecasted for sale by the Company at Mont Belvieu, Texas-posted prices for 2016 with a fixed price of $8.93 per Bbl and (ii) 3,000 Bbls per day of swap contracts for propane forecasted for sale by the Company at Mont Belvieu, Texas-posted prices for 2016 with a fixed price of $20.76 per Bbl.

Gas production derivative activities. All material physical sales contracts governing the Company's gas production are tied directly or indirectly to NYMEX Henry Hub ("HH") gas prices or regional index prices where the gas is sold. The Company uses derivative contracts to manage gas price volatility and basis swap contracts to reduce basis risk between HH prices and the actual index prices at which the gas is sold.

The following table sets forth the volumes per day associated with the Company's outstanding gas derivative contracts as of June 30, 2015 and the weighted average gas prices for those contracts:

	Six Months Ending December 31,	Year Ending December 31,	
	2015	2016	2017
Swap contracts:			
Volume (MMBtu)	20,000	70,000	—
Price per MMBtu	$4.31	$4.06	$—
Collar contracts with short puts:			
Volume (MMBtu) (a)	285,000	140,000	—
Price per MMBtu:			
Ceiling	$5.07	$4.09	$—
Floor	$4.00	$3.27	$—
Short put	$3.00	$2.79	$—
Basis swap contracts:			
Gulf Coast index swap volume (b)	20,000	10,000	—
Price differential ($/MMBtu)	$—	$—	$—
Mid-Continent index swap volume (b)	95,000	15,000	45,000
Price differential ($/MMBtu)	$(0.24)	$(0.32)	$(0.32)
Permian Basin index swap volume (b)	10,000	—	—
Price differential ($/MMBtu)	$(0.13)	$—	$—
Permian Basin index swap volume (c)(d)	35,055	—	—
Price differential ($/MMBtu)	$0.20	$—	$—

(a) Subsequent to June 30, 2015, the Company entered into an additional 40,000 MMBtu per day of 2016 collar contracts with short puts with a ceiling price of $3.71 per MMBtu, a floor price of $3.15 per MMBtu and a short put price of $2.75 per MMBtu.

(b) Represent swaps that fix the basis differentials between the index prices at which the Company sells its Gulf Coast, Mid-Continent and Permian Basin gas, respectively, and the NYMEX Henry Hub index price used in gas swap and collar contracts.

(c) Represent swaps that fix the basis differentials between Permian Basin index prices and southern California index prices for Permian Basin gas forecasted for sale in southern California.

(d) Subsequent to June 30, 2015, the Company entered into gas index swap contracts for an additional 30,000 MMBtu per day of August 2015 gas with a price differential of $0.21 per MMBtu between Permian Basin index prices and southern California index prices.

Marketing and basis differential derivative activities. Periodically, the Company enters into buy and sell marketing arrangements to fulfill firm pipeline transportation commitments. Associated with these marketing arrangements, the Company may enter into index swaps to mitigate price risk. As of June 30, 2015, the Company had marketing oil index swap contracts for 10,000 Bbl per day for the remainder of 2015 with a price differential of $2.99 per Bbl between Cushing WTI and Louisiana Light Sweet oil.

Interest rate derivative activities. During the three months ended June 30, 2015, the Company terminated its interest rate derivative contracts for cash proceeds of $2 million.

Tabular disclosure of derivative financial instruments. All of the Company's derivatives are accounted for as non-hedge derivatives and therefore all changes in the fair values of its derivative contracts are recognized as gains or losses in the earnings of the periods in which they occur. The Company classifies the fair value amounts of derivative assets and liabilities as net current or noncurrent derivative assets or net current or noncurrent derivative liabilities, whichever the case may be, by commodity and

counterparty. The Company enters into derivatives under master netting arrangements, which, in an event of default, allows the Company to offset payables to and receivables from the defaulting counterparty.
The aggregate fair value of the Company's derivative instruments reported in the consolidated balance sheets by type and counterparty, including the classification between current and noncurrent assets and liabilities, consists of the following:

Fair Value of Derivative Instruments as of June 30, 2015

Type	Consolidated Balance Sheet Location	Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
		(in millions)		
Derivatives not designated as hedging instruments				
Asset Derivatives:				
Commodity price derivatives	Derivatives - current	$357	$(3)	$354
Commodity price derivatives	Derivatives - noncurrent	$95	$(6)	89
				$443
Liability Derivatives:				
Commodity price derivatives	Derivatives - current	$3	$(3)	$—
Commodity price derivatives	Derivatives - noncurrent	$7	$(6)	1
				$1

Fair Value of Derivative Instruments as of December 31, 2014

Type	Consolidated Balance Sheet Location	Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
		(in millions)		
Derivatives not designated as hedging instruments				
Asset Derivatives:				
Commodity price derivatives	Derivatives - current	$579	$(1)	$578
Commodity price derivatives	Derivatives - noncurrent	$182	$(1)	181
				$759
Liability Derivatives:				
Commodity price derivatives	Derivatives - current	$1	$(1)	$—
Interest rate derivatives	Derivatives - current	$3	$—	3
Commodity price derivatives	Derivatives - noncurrent	$3	$(1)	2
				$5

The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures.

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The following table details the location of gains and losses recognized on the Company's derivative contracts in the accompanying consolidated statements of operations:

Derivatives Not Designated as Hedging Instruments	Location of Gain / (Loss) Recognized in Earnings on Derivatives	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
		(in millions)			
Commodity price derivatives	Derivative gains (losses), net	$(212)	$(226)	$39	$(340)
Interest rate derivatives	Derivative gains (losses), net	15	8	5	18
Total		$(197)	$(218)	$44	$(322)

NOTE F. Exploratory Costs

The Company capitalizes exploratory well and project costs until a determination is made that the well or project has either found proved reserves, is impaired or is sold. The Company's capitalized exploratory well and project costs are presented in proved properties in the accompanying consolidated balance sheets. If the exploratory well or project is determined to be impaired, the impaired costs are charged to exploration and abandonments expense.

The following table reflects the Company's capitalized exploratory well and project activity during the three and six months ended June 30, 2015:

	Three Months Ended June 30, 2015	Six Months Ended June 30, 2015
	(in millions)	
Beginning capitalized exploratory costs	$310	$305
Additions to exploratory costs pending the determination of proved reserves	235	461
Reclassification due to determination of proved reserves	(265)	(481)
Exploratory well costs charged to exploration expense	(10)	(15)
Ending capitalized exploratory costs	$270	$270

As of June 30, 2015 and December 31, 2014, the Company had no exploratory projects for which exploratory costs have been capitalized for a period greater than one year from the date drilling was completed.

NOTE G. Long-term Debt

The Company's long-term debt consists of senior notes and a revolving corporate credit facility (the "Credit Facility"), including the effects of net deferred fair value hedge losses and issuance discounts. The Credit Facility is maintained with a syndicate of financial institutions and has aggregate loan commitments of $1.5 billion that expire in December 2017. As of June 30, 2015, the Company had no outstanding borrowings under the Credit Facility and was in compliance with its debt covenants.

NOTE H. Incentive Plans

Stock-based compensation

For the three and six months ended June 30, 2015, the Company recorded $32 million and $61 million, respectively, of stock-based compensation expense for all plans, as compared to $33 million and $62 million for the same respective periods of 2014. As of June 30, 2015, there was $164 million of unrecognized compensation expense related to unvested share-based compensation plan awards, including $30 million attributable to stock-based awards that are expected to be settled on their vesting date in cash, rather than in equity shares ("Liability Awards"). The unrecognized compensation expense will be recognized over the remaining vesting periods of the awards, which is a period of less than three years on a weighted average basis. As of June 30, 2015 and December 31, 2014, accounts payable – due to affiliates includes $11 million and $23 million, respectively, of liabilities attributable to Liability Awards.

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The following table summarizes the activity that occurred during the six months ended June 30, 2015, for each type of share-based incentive award issued by Pioneer:

	Restricted Stock Equity Awards	Restricted Stock Liability Awards	Performance Units	Stock Options
Outstanding as of December 31, 2014	1,233,539	328,087	154,733	199,058
Awards granted	435,462	158,726	82,431	—
Awards vested	(508,335)	(173,759)	—	—
Awards forfeited	(10,859)	(13,997)	—	—
Outstanding as of June 30, 2015	1,149,807	299,057	237,164	199,058

NOTE I. Asset Retirement Obligations

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and facilities. The following table summarizes the Company's asset retirement obligation activity during the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Beginning asset retirement obligations	$ 188	$ 194	$ 189	$ 194
New wells placed on production	—	1	1	2
Changes in estimates	—	—	—	1
Dispositions	—	—	—	(1)
Liabilities settled	(4)	(5)	(9)	(9)
Accretion of discount	3	3	6	6
Ending asset retirement obligations	$ 187	$ 193	$ 187	$ 193

The Company records the current and noncurrent portions of asset retirement obligations in other current liabilities and other liabilities, respectively, in the accompanying consolidated balance sheets. As of June 30, 2015, the current portion of the Company's asset retirement obligations was $33 million, as compared to $28 million at December 31, 2014.

NOTE J. Commitments and Contingencies

The Company is a party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to such proceedings and claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company records reserves for contingencies when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

Obligations following divestitures. In connection with its divestiture transactions, the Company may retain certain liabilities and provide the purchaser certain indemnifications, subject to defined limitations, which may apply to identified pre-closing matters, including matters of litigation, environmental contingencies, royalty obligations and income taxes. The Company does not believe these obligations are probable of having a material impact on its liquidity, financial position or future results of operations.

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NOTE K. Interest and Other Income

The following table provides the components of the Company's interest and other income for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Equity interest in income of EFS Midstream (a)	$3	$3	$5	$6
Income (loss) from vertical integration services (b)	5	(5)	4	(7)
Deferred compensation plan income	—	—	3	2
Other income	3	5	5	6
Total interest and other income	$11	$3	$17	$7

(a) The Company accounts for its investment in EFS Midstream LLC ("EFS Midstream") using the equity method. EFS Midstream provides gathering, treating and transportation services for the Company. See Note O for additional information on the Company's sale of EFS Midstream in July 2015.

(b) Income (loss) from vertical integration services primarily represents net margins that result from Company-provided fracture stimulation and service operations, which are ancillary to and supportive of the Company's oil and gas joint operating activities, and do not represent intercompany transactions. For the three and six months ended June 30, 2015, these vertical integration net margins included $86 million and $198 million, respectively, of revenues and $81 million and $194 million, respectively, of costs and expenses. For the same period in 2014, these vertical integration net margins included $104 million and $196 million, respectively, of revenues and $109 million and $203 million, respectively, of costs and expenses.

NOTE L. Other Expense

The following table provides the components of the Company's other expense for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Idle drilling and well service equipment charges (a)	$28	$—	$51	$—
Transportation commitment charge (b)	13	12	27	22
Restructuring charges (c)	15	—	15	—
Impairment of inventory (d)	3	4	9	4
Other	3	5	8	10
Total other expense	$62	$21	$110	$36

(a) Primarily represents expenses attributable to idle drilling rig fees, which are not chargeable to joint operations.

(b) Primarily represents firm transportation payments on excess pipeline capacity commitments.

(c) Represents one-time restructuring costs in connection with the Company's plans to restructure its operations in Colorado, including closing its office in Denver, Colorado and eliminating its Trinidad-based pumping services operations. See Note B for additional information on the restructuring charges.

(d) Represents charges to reduce excess material and supplies inventories to their market values. See Note D for additional information on the fair value of materials and supplies inventory.

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NOTE M. Income Taxes

The Company's income tax benefit (provision) attributable to income from continuing operations consisted of the following for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Current tax provision	$(1)	$(6)	$(1)	$(18)
Deferred tax benefit (provision)	124	(26)	161	(65)
Income tax benefit (provision)	$123	$(32)	$160	$(83)

For the three and six months ended June 30, 2015, the Company's effective tax rates, excluding income attributable to noncontrolling interests, were 36 percent and 35 percent, as compared to effective rates of 37 percent and 29 percent for the same respective periods in 2014. The Company's effective tax rates differed from the U.S. statutory rate of 35 percent primarily due to state income tax apportionments, nondeductible expenses and, for the six months ended June 30, 2014, the recognition of a $21 million tax benefit resulting from the resolution during the first quarter of 2014 of a tax uncertainty related to net operating loss carryovers and alternative minimum tax credits obtained from the 2012 acquisition of Premier Silica. The Company has no unrecognized tax benefits as of June 30, 2015.

The Company files income tax returns in the U.S. federal and various state and foreign jurisdictions. The Internal Revenue Service has closed examinations of the 2012 and prior tax years and, with few exceptions, the Company believes that it is no longer subject to examinations by state and foreign tax authorities for years before 2009. As of June 30, 2015, no adjustments had been proposed in any jurisdiction that would have a significant effect on the Company's liquidity, future results of operations or financial position.

NOTE N. Net Income (Loss) Per Share

The following table reconciles the Company's income (loss) from continuing operations to basic and diluted net income (loss) attributable to common stockholders for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Income (loss) from continuing operations	$(217)	$55	$(292)	$200
Participating basic earnings	—	—	—	(1)
Basic and diluted income (loss) from continuing operations	$(217)	$55	(292)	199
Basic and diluted loss from discontinued operations	$(1)	$(54)	$(4)	$(76)
Basic and diluted net income (loss) attributable to common stockholders	$(218)	$1	$(296)	$123

Basic and diluted weighted average common shares outstanding were 149 million for the three and six months ended June 30, 2015 and 143 million for the three and six months ended June 30, 2014.

NOTE O. Subsequent Events

EFS Midstream. During November 2014, the Company announced that it was pursuing the divestment of its 50.1 percent equity interest in EFS Midstream. The Company accounts for EFS Midstream under the equity method of accounting for investments in unconsolidated affiliates. In June 2015, the Company entered into a purchase and sale agreement to sell its interest in EFS Midstream to an unaffiliated third party. The sale closed in July 2015, with the Company receiving total consideration of $1.0 billion, of which $530 million was received at closing and the remaining approximately $500 million will be received in July 2016. Associated with the sale, the Company expects to record a pretax gain in excess of $725 million during the third quarter of 2015.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Financial and Operating Performance

The Company's financial and operating performance for the second quarter of 2015 included the following highlights:

- Net loss attributable to common stockholders for the second quarter of 2015 was $218 million ($1.46 per diluted share), as compared to net income of $1 million ($0.01 per diluted share) for the second quarter of 2014. The decrease in net income attributable to common stockholders is comprised of a $272 million decrease in net income from continuing operations attributable to common stockholders, offset by a $53 million decrease in loss from discontinued operations, net of tax.

The primary components of the decrease in net income from continuing operations include:

- a $342 million decrease in oil and gas revenues as a result of a 43 percent decrease in the average commodity prices per BOE, partially offset by a 12 percent increase in sales volumes;
- an $86 million increase in DD&A expense, primarily attributable to the 12 percent increase in sales volumes and reductions in proved reserves as a result of the recent decline in commodity prices; and
- a $41 million increase in other expense, primarily related to idle drilling rig charges and restructuring charges associated with the closing of the Company's Denver, Colorado office; partially offset by
- a $23 million decrease in total oil and gas production costs and production and ad valorem taxes, primarily associated with the 43 percent decrease in average commodity prices per BOE;
- a $21 million decrease in net derivative losses, primarily as a result of changes in forward commodity prices and the Company's portfolio of derivatives; and
- a $155 million decrease in the Company's income tax provision as a result of the Company's decrease in income from continuing operations before taxes.

The loss from discontinued operations, net of tax, during the three months ended June 30, 2014 was attributable to the results of operations (prior to their sale) associated with the Company's sales of Pioneer Alaska in April 2014 and its Hugoton field assets and Barnett Shale field assets in September 2014.

- During the second quarter of 2015, average daily sales volumes from continuing operations increased by 12 percent to 196,626 BOEPD, as compared to 175,834 BOEPD during the second quarter of 2014. The increase in second quarter 2015 average daily sales volumes, as compared to the second quarter of 2014, is primarily due to the Company's successful Spraberry/Wolfcamp and Eagle Ford Shale drilling programs.
- Average oil, NGL and gas prices decreased during the second quarter of 2015 to $51.64 per Bbl, $14.03 per Bbl and $2.37 per Mcf, respectively, as compared to $95.87 per Bbl, $30.24 per Bbl and $4.33 per Mcf, respectively, in the second quarter of 2014.
- Net cash provided by operating activities decreased to $327 million for the three months ended June 30, 2015, as compared to $718 million for the three months ended June 30, 2014. The $391 million decrease in net cash provided by operating activities is primarily due to the decrease in oil, NGL and gas prices, partially offset by an increase in net cash flows from derivative settlements and an increase in oil and gas sales volumes.
- As of June 30, 2015, the Company's net debt to book capitalization increased to 23 percent, as compared to 16 percent at December 31, 2014, due to the use of cash and cash equivalents to fund the Company's drilling program.

Recent Developments

Commodity prices. North American and worldwide oil, NGL and gas prices remain under pressure given the current over supply of such commodities. In general, this imbalance between supply and demand reflects the significant supply growth achieved in the United States as a result of shale drilling and the recent OPEC oil production increases as part of an effort to retain market share combined with only modest demand growth in the United States and slowing demand in other parts of the world, particularly in Europe and China. Although there has been a dramatic decrease in drilling activity in the industry, oil and NGL storage levels in the United States remain at historically high levels. Until this overhang in storage levels begins to decline, prices are expected to remain under pressure. In addition, the possible lifting of economic sanctions on Iran has caused the market to anticipate increased supplies of oil from Iran in early 2016, further weakening the outlook for oil prices. The reduced demand for drilling rigs, oilfield supplies, drill pipe and utilities, for which prices had reached very high levels during a period of high utilization in 2014, has led to a decline of these costs. However, their declines have significantly lagged behind the declines in oil, NGL and gas prices. As a result of these circumstances, the Company experienced significant operating margin deterioration during the first half of 2015.

The duration and magnitude of the commodity price declines and the timing and amount of cost reductions cannot be accurately predicted.

Low price environment initiatives. In the midst of the lower commodity price environment, the Company has implemented initiatives to improve drilling and completion efficiencies and reduce capital spending, operating costs and general and administrative expenses to minimize spending in excess of estimated cash flows for 2015 and to maintain significant financial flexibility. As a result of these initiatives, the Company has realized significant service cost reductions and efficiency gains that have resulted in (i) an estimated 20 percent to 25 percent decrease in drilling and completion costs compared to 2014 and (ii) a 17 percent reduction in second quarter lease operating expenses per BOE compared to 2014. Drilling and completion costs are expected to be reduced by more than 30 percent by early 2016 compared to 2014 levels as additional cost reductions and efficiency gains are achieved.

EFS Midstream. During November 2014, the Company announced that it was pursuing the divestment of its 50.1 percent equity interest of EFS Midstream. During June 2015, the Company entered into a purchase and sale agreement to sell its interest in EFS Midstream to an unaffiliated third party. The sale closed in July 2015, with the Company receiving total consideration of $1.0 billion, of which $530 million was received at closing and the remaining approximately $500 million will be received in July 2016. Associated with the sale, the Company expects to record a pretax gain in excess of $725 million during the third quarter of 2015. In conjunction with this transaction, the Company also extended its downstream processing and transportation contracts to 20 years, with improved terms.

Drilling Rig Additions. With the completion of the EFS Midstream sale, along with the benefits of the Company's cost savings and efficiency initiatives, the Company began adding horizontal rigs in the northern Spraberry/Wolfcamp area in July 2015, and plans to add an average of two horizontal rigs per month for the remainder of 2015. The Company plans to evaluate its decision to add drilling rigs each month based on the Company's outlook for commodity prices and continuing efficiency improvements, which are reducing the number of days required to place wells on production. This additional drilling activity is expected to increase the Company’s 2015 capital budget by approximately $350 million to a total of $2.2 billion. Due to the timing associated with multi-well pad drilling, the addition of the rigs is expected to have minimal impact on 2015 production.

Third Quarter 2015 Outlook

Based on current estimates, the Company expects the following operating and financial results from continuing operations for the quarter ending September 30, 2015:

Production is forecasted to average 205,000 to 210,000 BOEPD.

Production costs (including production and ad valorem taxes and transportation costs) are expected to average $11.50 to $13.50 per BOE based on current NYMEX strip commodity prices and reflects a $0.75 per BOE to $1.00 per BOE increase from second quarter 2015 production costs as a result of the sale of EFS Midstream. DD&A expense is expected to average $18.00 to $20.00 per BOE, reflecting an anticipated further decline in proved reserves as a result of lower commodity prices reducing the economic lives of the Company's producing wells.

Total exploration and abandonment expense is expected to be $25 million to $35 million. General and administrative expense is expected to be $80 million to $85 million. Interest expense is expected to be $45 million to $50 million, and other expense is expected to be $45 million to $55 million, excluding anticipated nonrecurring restructuring charges during the quarter of approximately $10 million. Accretion of discount on asset retirement obligations is expected to be $3 million to $5 million.

The Company's effective income tax rate is expected to range from 35 percent to 40 percent assuming current capital spending plans and no significant mark-to-market changes in the Company's derivative position. Current income taxes are expected to range from $45 million to $55 million and are primarily attributable to (i) estimated federal alternative minimum taxes associated with the sale of the Company's interest in EFS Midstream during July 2015 and (ii) state taxes.

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Operations and Drilling Highlights
The following table summarizes the Company's average daily oil, NGL, gas and total production by asset area during the six months ended June 30, 2015:

	Oil (Bbls)	NGLs (Bbls)	Gas (Mcf)	Total (BOE)
Permian Basin	76,146	21,201	107,358	115,239
South Texas - Eagle Ford Shale	18,701	11,617	96,855	46,460
Raton Basin	—	—	115,323	19,221
West Panhandle	2,851	3,036	13,236	8,093
South Texas - Other	1,867	161	25,078	6,207
Other	2	—	51	12
Total	99,567	36,015	357,901	195,232

The Company's total liquids production from continuing operations increased to 69 percent of total production, on a BOE basis, for the six months ended June 30, 2015, as compared to 67 percent for the same period last year.

The following table summarizes by geographic area the Company's finding and development costs incurred during the six months ended June 30, 2015:

	Unproved Acquisition Costs	Exploration Costs	Development Costs	Total
	(in millions)			
Permian Basin	$9	$364	$343	$716
South Texas - Eagle Ford Shale	—	121	92	213
Raton Basin	—	1	1	2
West Panhandle	—	—	5	5
South Texas - Other	—	1	—	1
Other	—	8	—	8
Total	$9	$495	$441	$945

The following table summarizes the Company's development and exploration/extension drilling activities for the six months ended June 30, 2015:

	Development Drilling			
	Beginning Wells in Progress	Wells Spud	Successful Wells	Ending Wells in Progress
Permian Basin	41	32	55	18
South Texas - Eagle Ford Shale	13	19	15	17
Total	54	51	70	35

	Exploration/Extension Drilling				
	Beginning Wells in Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells in Progress
Permian Basin	75	36	62	—	49
South Texas - Eagle Ford Shale	30	33	32	1	30
Other	1	—	—	1	—
Total	106	69	94	2	79

Permian Basin area. The Company reduced its rig count during the first six months of 2015 to 10 rigs in the Spraberry/Wolfcamp area, all of which were drilling horizontal wells. With the completion of the EFS Midstream sale, along with the benefit of the Company's cost savings and efficiency initiatives, the Company began adding horizontal rigs in the northern Spraberry/Wolfcamp area in July 2015, and plans to add an average of two horizontal rigs per month for the remainder of 2015. The Company plans to evaluate its decision to add drilling rigs each month based on the Company's outlook for commodity prices and continuing efficiency improvements, which are reducing the number of days required to place wells on production. During 2015, the Company expects to drill approximately 105 horizontal wells (60 horizontal wells in the northern portion of the play and 45 horizontal wells in the southern portion of the play), with the horizontal wells being predominantly drilled in the Wolfcamp B horizon. The Company continues to drill utilizing two-well and three-well pads. The Company expects to spend $1.5 billion of drilling capital in the Spraberry/Wolfcamp area during 2015. During the first six months of 2015, the Company successfully completed 117 wells in the Permian Basin area, the majority of which were spud in 2014.

The Company continues to utilize its integrated services to control well costs and operating costs in addition to supporting the execution of its drilling and production activities in the Spraberry/Wolfcamp area. The Company is currently utilizing six Company-owned fracture stimulation fleets totaling approximately 307,000 horsepower in the Spraberry/Wolfcamp area. To support its operations, the Company also owns other field service equipment, including pulling units, fracture stimulation tanks, water transport trucks, hot oilers, blowout preventers, construction equipment and fishing tools. In addition, Premier Silica (the Company's wholly-owned sand mining subsidiary) is supplying brown sand for proppant, which is being used by the Company to fracture stimulate horizontal wells in the Spraberry and Wolfcamp Shale intervals.

The Company has been aggressively pursuing initiatives to improve drilling and completion efficiencies and reduce costs. A 20 percent to 25 percent reduction in drilling and completion costs in 2015 compared to 2014 has already been realized associated with these initiatives. The most significant drilling and completion cost reductions to date have been for materials for drilling and fracture stimulation, fuel charges, labor and transportation, rental equipment and well services, while efficiency gains include optimizing completions, expanding the use of a modified three-string casing design in the Spraberry/Wolfcamp, testing of dissolvable plug technologies and testing fracture stimulation diversion technologies. The Company expects further drilling and completion cost reductions and efficiency gains to exceed 30 percent by early 2016 compared to 2014, with the key incremental cost reductions being attributable to casing, tubing and well stimulation costs.

The Company's long-term growth plan continues to be focused on optimizing the development of the field and addressing the future requirements for water, field infrastructure, gas processing, sand, pipeline takeaway, oilfield services, tubulars, electricity, systems, buildings and roads. However, much of the Company's front-end loaded infrastructure plans, which were expected to provide significant future cost savings and support the Company's long-term growth plan in the Spraberry/Wolfcamp area, have been deferred given the significant decline in oil prices. The Company plans to continue to evaluate its infrastructure plans for a field-wide water distribution network, additional gas processing facilities and expansion of Premier Silica's Brady sand mine based on the Company's outlook for commodity prices and/or cost reductions. Savings of 20 percent are now being realized in the cost of constructing new facilities, with efforts underway to achieve further cost reductions. By early 2016, costs to construct facilities, particularly horizontal tank batteries and saltwater disposal systems, are expected to be lower by 25 percent, compared to 2014.

Eagle Ford Shale area. In the Eagle Ford Shale play in South Texas, the horizontal rig count has been reduced to six rigs. The Company expects to drill approximately 95 horizontal wells in the Eagle Ford Shale during 2015. The Company plans to spend $390 million of drilling capital in 2015. The 2015 drilling program has been focused on liquids-rich drilling in the lower and upper Eagle Ford intervals in Karnes and DeWitt counties, where the Company has drilled its most productive wells in the Eagle Ford Shale. No wells are scheduled to be drilled in dry gas acreage. The Company completed 48 horizontal Eagle Ford Shale wells during the first six months of 2015, 47 of which were successful, with average lateral lengths of approximately 5,600 feet and, on average, 24-stage fracture stimulations. The Company has placed 25 upper target Eagle Ford Shale wells on production and estimates that approximately 25 percent of the Company's acreage is prospective for this interval in the Eagle Ford Shale play. The Company is operating two Pioneer-owned fracture stimulation fleets in the play.

The Company's drilling operations in the Eagle Ford Shale continue to focus on improving drilling and completion efficiencies and cost reductions. A 20 percent reduction in drilling and completion costs in 2015 compared to 2014 has already been realized associated with these initiatives. The Company expects drilling and completion cost reductions and further efficiency gains in excess of 25 percent in early 2016 as compared to 2014 as additional cost reduction initiatives and efficiencies are realized. During 2015, most Eagle Ford Shale wells have been drilled utilizing two to five-well pads. Pad drilling saves the Company a significant amount of capital costs per well, as compared to drilling single-well locations.

During November 2014, the Company announced that it was pursuing the divestment of its 50.1 percent equity interest in EFS Midstream. During June 2015, the Company entered into a purchase and sale agreement to sell its share of EFS Midstream to an unaffiliated third party. The sale was closed in July 2015, with the Company receiving total consideration of $1.0 billion, of which $530 million was received at closing and the remaining approximately $500 million will be received in July 2016. Associated with the sale, the Company expects to record a pretax gain in excess of $725 million during the third quarter of 2015. As a result of the sale, the Company will no longer receive its share of the cash flow generated by EFS Midstream, which will increase the Company's oil and gas production costs by $0.75 per BOE to $1.00 per BOE.

Results of Operations from Continuing Operations

Oil and gas revenues. Oil and gas revenues totaled $596 million and $1.1 billion for the three and six months ended June 30, 2015, respectively, as compared to $938 million and $1.8 billion for the same respective periods in 2014.

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The decrease in oil and gas revenues during the three months ended June 30, 2015, as compared to the same period in 2014, is primarily due to declines of 46 percent, 54 percent and 45 percent in average oil, NGL and gas prices, respectively, and a five percent decline in daily NGL sales volumes, partially offset by 26 percent and three percent increases in daily oil and gas sales volumes, respectively. The decrease in oil and gas revenues during the six months ended June 30, 2015, as compared to the same period in 2014, is primarily due to declines of 50 percent, 54 percent and 44 percent in average oil, NGL and gas prices, respectively, partially offset by 26 percent and seven percent increases in daily oil and gas sales volumes, respectively.

The following table provides average daily sales volumes for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Oil (Bbls)	100,569	79,780	99,567	79,188
NGLs (Bbls)	36,659	38,572	36,015	36,049
Gas (Mcf)	356,391	344,889	357,901	333,210
Total (BOEs)	196,626	175,834	195,232	170,772

Average daily BOE sales volumes increased by 12 percent and 14 percent for the three and six months ended June 30, 2015, respectively, as compared to the same periods in 2014, principally due to the Company's successful Spraberry/Wolfcamp and Eagle Ford Shale drilling programs.

Production during the six months ended June 30, 2015 reflects a production loss of approximately 1,600 BOEPD in the Spraberry/Wolfcamp area due to heavy icing and low temperatures during January that resulted in extensive power outages, facility freeze-ups, trucking curtailments and limited access to production and drilling facilities. In addition, production for the six months ended June 30, 2015 reflects lower NGL production volumes of approximately 5,000 barrels per day due to voluntary reductions in recoveries of ethane since it had a higher value if sold as part of the gas stream.

The oil, NGL and gas prices that the Company reports are based on the market prices received for each commodity. The following table provides the Company's average prices for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Oil (per Bbl)	$51.64	$95.87	$47.40	$94.15
NGL (per Bbl)	$14.03	$30.24	$14.50	$31.43
Gas (per Mcf)	$2.37	$4.33	$2.53	$4.53
Total (per BOE)	$33.32	$58.63	$31.50	$59.14

Sales of purchased oil and gas. The Company periodically enters into pipeline capacity commitments in order to secure available oil, NGL and gas transportation capacity from the Company’s areas of production. The Company enters into purchase transactions with third parties and separate sale transactions with third parties to diversify a portion of the Company's WTI oil sales to a Gulf Coast oil price and to satisfy unused pipeline capacity commitments. Revenues and expenses from these transactions are presented on a gross basis as the Company acts as a principal in the transaction by assuming the risk and rewards of ownership, including credit risk, of the commodities purchased and assuming responsibility to deliver the commodities sold. Firm transportation payments on excess pipeline capacity commitments are included in other expense in the accompanying consolidated statements of operations. See Note L of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" for further information on transportation commitment charges.

Interest and other income. Interest and other income for the three and six months ended June 30, 2015 was $11 million and $17 million, respectively, as compared to $3 million and $7 million for the same respective periods in 2014. The increase in interest and other income for both the three and six months ended June 30, 2015, as compared to the same respective periods in 2014, is primarily due to an increase in net margins that result from Company-provided fracture

stimulation and related service operations that do not represent intercompany transactions, See Note K of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" for additional information.
Derivative gains (losses), net. The Company utilizes commodity swap contracts, collar contracts and collar contracts with short puts to (i) reduce the effect of price volatility on the commodities the Company produces and sells or consumes, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. During the three and six months ended June 30, 2015, the Company recorded $197 million of net derivative losses and $44 million of net derivative gains, respectively, on commodity price and interest rate derivatives, of which $150 million and $356

million represented net cash receipts, respectively. During the three and six months ended June 30, 2014, the Company recorded $218 million and $322 million of net derivative losses, respectively, of which $6 million and $24 million reflected net cash payments, respectively.

The following tables detail the net cash receipts (payments) on the Company's commodity derivatives and the relative price impact (per Bbl or Mcf) for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30, 2015			Six Months Ended June 30, 2015		
	Net cash receipts (in millions)	Price impact		Net cash receipts (in millions)	Price impact	
Oil derivative receipts	$118	$12.96	per Bbl	$299	$16.60	per Bbl
NGL derivative receipts	3	$0.85	per Bbl	2	$0.29	per Bbl
Gas derivative receipts	30	$0.91	per Mcf	56	$0.87	per Mcf
Total net commodity derivative receipts	$151			$357		

	Three Months Ended June 30, 2014			Six Months Ended June 30, 2014		
	Net cash receipts (payments) (in millions)	Price impact		Net cash receipts (payments) (in millions)	Price impact	
Oil derivative payments	$(11)	$(1.24)	per Bbl	$(14)	$(0.86)	per Bbl
NGL derivative receipts	1	$0.28	per Bbl	1	$0.13	per Bbl
Gas derivative payments	(10)	$(0.31)	per Mcf	(29)	$(0.49)	per Mcf
Total net commodity derivative payments	$(20)			$(42)		

See Notes D and E of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" and "Item 3. Quantitative and Qualitative Disclosures About Market Risk" for additional information regarding the Company's derivative activities and market risks associated with those activities.

Gain on disposition of assets, net. The Company recorded net gains on the disposition of assets of $2 million and $3 million for the three and six months ended June 30, 2015, respectively, as compared to $4 million and $10 million for the same respective periods in 2014. See Note C of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" for additional information regarding the Company's gains and losses on the disposition of assets.

Oil and gas production costs. The Company recorded oil and gas production costs of $163 million and $343 million during the three and six months ended June 30, 2015, respectively, as compared to $167 million and $325 million during the same respective periods in 2014. Lease operating expenses and workover costs represent the components of oil and gas production costs over which the Company has management control, while third-party transportation charges represent the cost to transport volumes produced to a sales point. Net natural gas plant charges represent the net costs to gather and process the Company's gas, reduced by net revenues earned from the gathering and processing of third-party gas in Company-owned facilities.

Total oil and gas production costs per BOE for the three and six months ended June 30, 2015 decreased by 12 percent and eight percent, as compared to the same respective periods in 2014. The decrease in lease operating expenses per BOE during the three and six months ended June 30, 2015, as compared to the same respective periods in 2014, is primarily due to cost reduction initiatives and lower electricity and fuel costs, which are impacted by lower commodity prices. The increase in net natural gas plant charges per BOE during the three and six months ended June 30, 2015, as compared to the same respective periods in 2014, is primarily reflective of reduced earnings on third-party volumes that are processed in Company-owned facilities due to lower NGL and gas prices.

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The following table provides the components of the Company's oil and gas production costs per BOE for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Lease operating expenses	$6.84	$8.32	$7.32	$8.38
Third-party transportation charges	1.56	1.89	1.56	1.79
Net natural gas plant charges	0.08	(0.42)	0.19	(0.35)
Workover costs	0.63	0.59	0.63	0.67
Total production costs	$9.11	$10.38	$9.70	$10.49

Production and ad valorem taxes. The Company's production and ad valorem taxes were $37 million and $76 million during the three and six months ended June 30, 2015, respectively, as compared to $56 million and $111 million for the same respective periods in 2014. In general, production and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, whereas production taxes are based upon current year commodity prices.

The following table provides the Company's production and ad valorem taxes per BOE for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Production taxes	1.38	2.28	$1.30	$2.32
Ad valorem taxes	$0.70	$1.24	0.86	1.28
Total production and ad valorem taxes	$2.08	$3.52	$2.16	$3.60

Depletion, depreciation and amortization expense. The Company's DD&A expense was $329 million ($18.38 per BOE) and $639 million ($18.08 per BOE) for the three and six months ended June 30, 2015, respectively, as compared to $243 million ($15.19 per BOE) and $460 million ($14.87 per BOE) during the same respective periods in 2014. The change in per BOE DD&A expense during the three and six months ended June 30, 2015, as compared to the same respective periods in 2014, is primarily due to an increase in depletion expense on oil and gas properties. Depletion expense on oil and gas properties was $17.75 and $17.45 per BOE during the three and six months ended June 30, 2015, respectively, as compared to $14.62 and $14.30 per BOE during the same respective periods in 2014. The change in per BOE depletion expense during the three and six months ended June 30, 2015, as compared to the same respective periods in 2014, is primarily due to (i) a decline in proved undeveloped reserves due to negative revisions of previous estimates during the fourth quarter of 2014 to remove undeveloped vertical well locations that are no longer expected to be drilled as a result of the Company shifting its planned capital expenditures to higher-rate-of-return horizontal drilling and (ii) the recent declines in commodity prices that led to a reduction to proved reserves as a result of shortening the economic productive lives of the Company's producing wells.

Impairment of oil and gas properties. The Company performs assessments of its long-lived assets to be held and used, including oil and gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable.

The cash flow model the Company uses to assess proved properties for impairment includes numerous assumptions. The primary factors that may affect estimates of future cash flows are (i) future reserve adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves (ii) results of future drilling activities, (iii) Management's Price Outlook and (iv) increases or decreases in production and capital costs associated with these fields. All inputs to the cash flow model must be evaluated at each measurement date.

During the first quarter of 2015, declines in Management's Price Outlook provided indications of possible impairment of the Company's oil and gas properties in the West Panhandle field. As a result of management's assessments, during the first quarter of 2015, the Company recognized a pretax noncash impairment charge of $138 million to reduce the carrying value of the West Panhandle field to its estimated fair value. The Company's estimates of undiscounted future net cash flows attributable to oil and gas properties on June 30, 2015 indicated that their carrying amounts were expected to be recovered, but continue to be at risk for impairment if estimates of future cash flows decline. It is reasonably possible that Management's Price Outlook could decline further during 2015 which may reduce the Company's estimate of undiscounted future net cash flows resulting in additional impairment charges to the Company's oil and gas properties.

Exploration and abandonments expense. The following table provides the Company's geological and geophysical costs, exploratory dry holes expense and lease abandonments and other exploration expense for the three and six months ended June 30, 2015 and 2014 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Geological and geophysical	$18	$25	$38	$49
Exploratory dry holes	10	3	15	4
Leasehold abandonments and other	—	—	1	6
	$28	$28	$54	$59

The Company's geological and geophysical costs decreased by $7 million and $11 million during the three and six months ended June 30, 2015, as compared to the same respective periods in 2014, primarily due to decreased seismic and seismic interpretation expenditures. During the three and six months ended June 30, 2015, the Company's exploratory dry hole expense increased by $7 million and $11 million, respectively, as compared to the same respective periods in 2014, primarily due to dry hole provisions related to unsuccessful exploration wells in eastern Colorado and the Eagle Ford Shale.

During the six months ended June 30, 2015, the Company drilled and evaluated 96 exploration/extension wells, 94 of which were successfully completed as discoveries. During the same period in 2014, the Company drilled and evaluated 129 exploration/extension wells, 128 of which were successfully completed as discoveries.

General and administrative expense. General and administrative expense for the three and six months ended June 30, 2015 was $83 million and $165 million, respectively, as compared to $82 million and $163 million for the same respective periods in 2014.

Accretion of discount on asset retirement obligations. Accretion of discount on asset retirement obligations was $3 million and $6 million for both the three and six months ended June 30, 2015 and 2014, respectively. See Note I of Notes to Consolidated Financial Statements in "Item 1. Financial Statements" for information regarding the Company's asset retirement obligations.

Interest expense. Interest expense was $46 million and $92 million for the three and six months ended June 30, 2015, respectively, as compared to $47 million and $92 million during the same respective periods in 2014. The weighted average interest rate on the Company's indebtedness for the three and six months ended June 30, 2015, including the effects of capitalized interest, was 6.7 percent and 6.6 percent, respectively, as compared to 6.4 percent and 6.8 percent for the same respective periods in 2014.

Other expense. Other expense was $62 million and $110 million for the three and six months ended June 30, 2015, respectively, as compared to $21 million and $36 million during the same respective periods in 2014. The increase in other expense for the three and six months ended June 30, 2015, as compared to the same respective periods in 2014, is primarily due to increases of $28 million and $51 million, respectively, in idle drilling and well service equipment charges, as well as a $15 million restructuring charge recorded in the second quarter of 2015 (see further information below).

In May 2015, the Company announced plans to restructure its operations in Colorado, including closing its office in Denver, Colorado and eliminating its Trinidad-based pumping services operations. The Company is also relocating a number of employees from Denver to its corporate headquarters in Irving, Texas. This initiative is expected to be substantially completed by the end of the third quarter of 2015.

Including the $15 million recognized during the three and six months ended June 30, 2015, the Company estimates that it will incur a total of approximately $25 million of one-time restructuring costs in connection with this restructuring plan. This estimate includes approximately $16 million in employee severance costs, $6 million in lease-related costs and $3 million in employee relocation and other costs. The expense is recognized in other expense on the accompanying consolidated statement of operations.

See Note L of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" for additional information.

Income tax benefit (provision). The Company recorded income tax benefits from continuing operations of $123 million and $160 million for the three and six months ended June 30, 2015, respectively, as compared to income tax provisions of $32 million and $83 million for the same respective periods in 2014. The Company's effective tax rate for the three and six months ended June 30, 2015 was 36 percent and 35 percent, respectively, as compared to 37 percent and 29 percent for the same respective periods in 2014. The difference between the effective tax rate and the statutory tax rate during the six months ended June 30, 2014 is primarily due to the recognition of a $21 million tax benefit related to net operating loss carryovers and alternative minimum tax credits obtained from the 2012 acquisition of Premier Silica. See Note M of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" for additional information regarding the Company's income taxes.

Loss from discontinued operations, net of tax. The Company reported losses from discontinued operations, net of tax, of $1 million and $4 million for the three and six months ended June 30, 2015, respectively, as compared to losses from discontinued operations, net of tax, of $54 million and $76 million for the same respective periods in 2014. The decrease in loss from discontinued operations for the three and six months ended June 30, 2015, as compared to the same respective periods in 2014, is primarily attributable to including the results of operations (prior to their sale) associated with the sale of Pioneer Alaska in April 2014 and the Hugoton field assets and Barnett Shale field assets in September 2014. See Note C of the Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" for specific information regarding the Company's discontinued operations.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. The Company's primary needs for cash are for capital expenditures and acquisition expenditures on oil and gas properties and related vertical integration assets and facilities, payment of contractual obligations, dividends and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, cash and cash equivalents on hand, proceeds from divestitures or external financing sources as discussed in "Capital resources" below.

The Company increased its capital budget for 2015 to $2.2 billion (excluding acquisitions, asset retirement obligations, capitalized interest and geological and geophysical administrative costs), which includes approximately $1.95 billion for drilling operations and $250 million related to planned expenditures for Spraberry/Wolfcamp water infrastructure, vertical integration and facilities. The Company's capital expenditures during the six months ended June 30, 2015 were $1.0 billion, consisting of $905 million for drilling operations (excluding acquisitions, asset retirement obligations, capitalized interest and geological and geophysical administrative costs) and $111 million for buildings, vertical integration and other plant and equipment additions. Based on results for the six months ended June 30, 2015 and Management's Price Outlook, the Company expects its net cash flows from operating activities, proceeds from the sale of EFS Midstream, cash and cash equivalents on hand and, if necessary, availability under the Credit Facility to be sufficient to fund its planned capital expenditures and contractual obligations for the remainder of 2015.

Investing activities. Investing activities used $1.2 billion of cash during the six months ended June 30, 2015, as compared to $1.1 billion of cash used in investing activities during the six months ended June 30, 2014. The increase in cash used in investing activities for the six months ended June 30, 2015, as compared to the six months ended June 30, 2014, is primarily due to (i) a $362 million decrease in proceeds from the disposition of assets and (ii) a $20 million increase in additions to other assets, partially offset by (iii) a $279 million decrease in additions to oil and gas properties. During the six months ended June 30, 2015, the Company's expenditures for investing activities were primarily funded by net cash provided by operating activities and cash on hand.

Dividends/distributions. During March of 2015 and February of 2014, the Board declared semiannual dividends of $0.04 per common share. Future dividends are at the discretion of the Board, and, if declared, the Board may change the current dividend amount based on the Company's liquidity and capital resources at the time.

Contractual obligations, including off-balance sheet obligations. The Company's contractual obligations include long-term debt, operating leases, drilling commitments, capital funding obligations, derivative obligations, firm transportation and fractionation commitments, minimum annual gathering, processing and transportation commitments and other liabilities (including postretirement benefit obligations). From time-to-time, the Company enters into arrangements and transactions that can give rise to material off-balance sheet obligations of the Company. As of June 30, 2015, the material off-balance sheet arrangements and transactions that the Company has entered into include (i) operating lease agreements, (ii) drilling commitments, (iii) firm purchase, transportation and fractionation commitments, (iv) open purchase commitments and (v) contractual obligations for which the ultimate settlement amounts are not fixed and determinable. The contractual obligations for which the ultimate settlement amounts are not fixed and determinable include (i) derivative contracts that are sensitive to future changes in commodity prices or interest rates, (ii) gathering, processing (primarily treating and fractionation) and transportation commitments on uncertain volumes of future throughput, (iii) open delivery commitments and (iv) indemnification obligations following certain divestitures. Other than the off-balance sheet arrangements described above, the Company has no transactions, arrangements or other relationships with unconsolidated entities or other parties that are reasonably likely to materially affect the Company's liquidity or availability of or requirements for capital resources. Since December 31, 2014, the primary changes in the Company's contractual obligations are a $312 million decrease in the fair value of the Company's derivative contracts. During the first quarter of 2015, the Company amended the majority of its drilling rig contracts. The amendments impacted the daily cost per rig and the timing of the commitments, but there was no material change to the overall obligations related to drilling rigs.

The Company's commodity and interest rate derivative contracts are periodically measured and recorded at fair value and continue to be subject to market or credit risk. As of June 30, 2015, these contracts represented net assets of $442 million. The ultimate liquidation value of the Company's commodity and interest rate derivatives will be dependent upon actual future commodity prices and interest rates, which may differ materially from the inputs used to determine the derivatives' fair values as of June 30, 2015. See Note E of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" and "Item 3. Quantitative and Qualitative Disclosures About Market Risk" for additional information about the Company's derivative instruments and market risk.

Capital resources. The Company's primary capital resources are cash and cash equivalents, net cash provided by operating activities, proceeds from divestitures and proceeds from financing activities (principally borrowings under the Company's Credit Facility or issuances of debt or equity securities). If internal cash flows and cash on hand do not meet the Company's expectations, the Company may reduce its level of capital expenditures, and/or fund a portion of its capital expenditures using availability under its Credit Facility, issue debt or equity securities or obtain capital from other sources, such as through sales of nonstrategic assets. The Company intends to refinance its outstanding senior notes that mature within the next two years ($455 million of 5.875% senior notes due July 15, 2016 and $485 million of 6.65% senior notes due March 15, 2017), subject to market conditions.

Operating activities. Net cash provided by operating activities during the six months ended June 30, 2015 was $432 million, as compared to $1.2 billion during the same period in 2014. The decrease in net cash provided by operating activities for the six months ended June 30, 2015, as compared to the six months ended June 30, 2014, is primarily due to declines in average oil, NGL and gas prices, partially offset by an increase in net cash flows from derivative settlements and an increase in oil and gas sales volumes.

Asset divestitures. During the six months ended June 30, 2014, the Company completed the sale of (i) Pioneer Alaska for cash proceeds of $267 million, (ii) Sendero for cash proceeds of $31 million (Sendero had $14 million of cash on hand at the time of the sale) and (iii) proved and unproved properties in Gaines and Dawson counties in the Spraberry field in West Texas for cash proceeds of $72 million.

Financing activities. Net cash used in financing activities during the six months ended June 30, 2015 was $32 million, as compared to net cash used in financing activities of $28 million during the same period in 2014.

As the Company pursues its strategy, it may utilize various financing sources, including fixed and floating rate debt, convertible securities, preferred stock or common stock. The Company cannot predict the timing or ultimate outcome of any such actions as they are subject to market conditions, among other factors. The Company may also issue securities in exchange for oil and gas properties, stock or other interests in other oil and gas companies or related assets. Additional securities may be of a class preferred to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined by the Board.

Liquidity. The Company's principal sources of short-term liquidity are cash on hand and unused borrowing capacity under its Credit Facility. As of June 30, 2015, the Company had no outstanding borrowings under its Credit Facility, leaving $1.5 billion of unused borrowing capacity. The Company was in compliance with all of its debt covenants as of June 30, 2015. The Company also had cash on hand of $219 million as of June 30, 2015. If internal cash flows and cash on hand do not meet the Company's expectations, the Company may reduce its level of capital expenditures, reduce dividend payments, and/or fund a portion of its capital expenditures using borrowings under its Credit Facility, issuances of debt or equity securities or other sources, such as sales of nonstrategic assets. The Company cannot provide any assurance that needed short-term or long-term liquidity will be available on acceptable terms or at all. Although the Company expects that the combination of internal operating cash flows, cash and cash equivalents on hand and, if necessary, available capacity under the Company's Credit Facility will be adequate to fund 2015 capital expenditures, dividend payments and provide adequate liquidity to fund other needs, no assurances can be given that such funding sources will be adequate to meet the Company's future needs.

Debt ratings. The Company is rated as investment grade by three credit rating agencies. The Company receives debt credit ratings from several of the major ratings agencies, which are subject to regular reviews. The Company believes that each of the rating agencies considers many factors in determining the Company's ratings including: production growth opportunities, liquidity, debt levels, asset composition and proved reserve mix. A reduction in the Company's debt ratings could increase the interest rates that the Company incurs on Credit Facility borrowings and could negatively impact the Company's ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Book capitalization and current ratio. The Company's net book capitalization at June 30, 2015 was $10.8 billion, consisting of $219 million of cash and cash equivalents, debt of $2.7 billion and equity of $8.3 billion. The Company's net debt to net book capitalization increased to 23 percent at June 30, 2015 from 16 percent at December 31, 2014, primarily due to payments in 2015 associated with the higher levels of drilling activity during the latter part of 2014, combined with a reduction in accounts payable, which resulted in a decrease to cash and cash equivalents of $806 million. The Company's ratio of current assets to current liabilities decreased to 1.26 to 1.00 at June 30, 2015, as compared to 1.49 to 1.00 at December 31, 2014, primarily due to the aforementioned decrease in cash and cash equivalents.

New accounting pronouncements. The effects of new accounting pronouncements are discussed in Note B of Notes to Consolidated Financial Statements included in "Item1. Financial Statements."

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following quantitative and qualitative disclosures about market risk are supplementary to the quantitative and qualitative disclosures provided in the Company's Annual Report on Form 10-K for the year ended December 31, 2014. As such, the information contained herein should be read in conjunction with the related disclosures in the Company's Annual Report on Form 10-K for the year ended December 31, 2014.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about the Company's potential exposure to market risks. The term "market risks," insofar as it relates to currently anticipated transactions of the Company, refers to the risk of loss arising from changes in commodity prices and interest rates. These 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 regarding how the Company views and manages ongoing market risk exposures. None of the Company's market risk sensitive instruments are entered into for speculative purposes.

The following table reconciles the changes that occurred in the fair values of the Company's open derivative contracts during the six months ending June 30, 2015:

	Derivative Contract Net Assets		
	Commodities	Interest Rates	Total
	(in millions)		
Fair value of contracts outstanding as of December 31, 2014	$ 757	$ (3)	$ 754
Changes in contract fair value	39	5	44
Contract maturity receipts	(354)	—	(354)
Contract terminations receipts	—	(2)	(2)
Fair value of contracts outstanding as of June 30, 2015	$ 442	$ —	$ 442

Interest rate sensitivity. See Note G of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" and Capital Commitments, Capital Resources and Liquidity included in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" for information regarding the Company's long-term debt.

The following table provides information about financial instruments to which the Company was a party as of June 30, 2015 and that are sensitive to changes in interest rates. The table presents debt maturities by expected maturity dates, the weighted average interest rates expected to be paid on the debt given current contractual terms and market conditions and the debt's estimated fair value. For fixed rate debt, the weighted average interest rate represents the contractual fixed rates that the Company was obligated to periodically pay on the debt as of June 30, 2015. Although the Company had no outstanding variable rate debt as of June 30, 2015, the average variable contractual rates for its credit facility projected forward proportionate to the forward yield curve for LIBOR on August 3, 2015 is presented in the table below.

	Six Months Ending December 31,	Year Ending December 31,						Liability Fair Value at June 30,
	2015	2016	2017	2018	2019	Thereafter	Total	2015
	(dollars in millions)							
Total Debt:								
Fixed rate principal maturities (a)	$—	$455	$485	$450	$—	$1,300	$2,690	$2,949
Weighted average fixed interest rate	6.15 %	6.17 %	6.11 %	5.91 %	5.80 %	5.81 %		
Average variable interest rate	1.94 %	2.47 %	3.16 %	— %	— %	— %		

(a) Represents maturities of principal amounts excluding debt issuance discounts and net deferred fair value hedge losses.

Commodity derivative instruments and price sensitivity. The following table provides information about the Company's oil, NGL and gas derivative financial instruments that were sensitive to changes in oil, NGL and gas prices as of June 30, 2015. Although mitigated by the Company's derivative activities, declines in oil, NGL and gas prices would reduce the Company's revenues.

The Company manages commodity price risk with derivative contracts, such as swap contracts, collar contracts and collar contracts with short put options. Swap contracts provide a fixed price for a notional amount of sales volumes. Collar contracts provide minimum ("floor" or "long put") and maximum ("ceiling") prices on a notional amount of sales volumes, thereby allowing some price participation if the relevant index price closes above the floor price. Collar contracts with short put options differ from other collar contracts by virtue of the short put option price, below which the Company's realized price will exceed the variable market prices by the long put-to-short put price differential.

See Note E of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" for a description of the accounting procedures followed by the Company relative to its derivative financial instruments and for specific information regarding the terms of the Company's derivative financial instruments that are sensitive to changes in oil, NGL or gas prices.

	Six Months Ending December 31, 2015	Year Ending December 31, 2016	Year Ending December 31, 2017	Asset (Liability) Fair Value at June 30, 2015 (a) (in millions)
Oil Derivatives:				
Average daily notional Bbl volumes:				
Swap contracts	82,000	—	—	$164
Weighted average fixed price per Bbl	$71.18	$—	$—	
Collar contracts with short puts (b)	15,000	100,514	15,000	$191
Weighted average ceiling price per Bbl	$97.69	$77.21	$73.01	
Weighted average floor price per Bbl	$82.97	$66.92	$65.00	
Weighted average short put price per Bbl	$69.67	$47.58	$55.00	
Average forward NYMEX oil prices (c)	$45.95	$50.44	$54.70	
Rollfactor swap contracts (d)	37,000	—	—	$3
Weighted average fixed price per Bbl	$0.06	$—	$—	
Average forward NYMEX rollfactor prices (c)	$(0.82)	$—	$—	
NGL Derivatives:				
Average daily notional Bbl volumes:				
Ethane swap contracts (f)	6,000	4,000	—	$9
Weighted average fixed price per Bbl	$7.80	$12.29	$—	
Average forward NGL prices (e)	$8.27	$8.79		
Propane swap contracts (f)	11,000	4,500	—	$—
Weighted average fixed price per Bbl	$21.62	$22.12	$—	
Average forward NGL prices (e)	$16.56	$18.18	$—	
Gas Derivatives:				
Average daily notional MMBtu volumes:				
Swap contracts (g)	20,000	70,000	—	$28
Weighted average fixed price per MMBtu	$4.31	$4.06	$—	
Collar contracts with short puts	285,000	140,000	—	$50
Weighted average ceiling price per MMBtu	$5.07	$4.09	$—	
Weighted average floor price per MMBtu	$4.00	$3.27	$—	
Weighted average short put price per MMBtu	$3.00	$2.79	$—	
Average forward NYMEX gas prices (c)	$2.87	$3.08		
Basis swap contracts:				$(2)
Gulf Coast basis swap contracts (h)	20,000	10,000	—	
Weighted average fixed price per MMBtu	$—	$—	$—	
Mid-Continent basis swap contracts (h)	95,000	15,000	45,000	
Weighted average fixed price per MMBtu	$(0.24)	$(0.32)	$(0.32)	
Permian Basin basis swap contracts (h)	10,000	—	—	
Weighted average fixed price per MMBtu	$(0.13)	$—	$—	
Weighted average forward basis differential prices (i)	$0.17	$0.19	$0.33	
Permian Basin basis swap contracts (j)(k)	35,055	—	—	
Weighted average fixed price per MMBtu	$0.20	$—	$—	
Weighted average forward basis differential prices (l)	$0.18	$—	$—	

(a) In accordance with Financial Accounting Standards Board ASC 210-20 and ASC 815-10, the Company classifies the fair value amounts of derivative assets and liabilities executed under master netting arrangements as net derivative assets or net derivative liabilities, as the case may be. The net asset and liability amounts shown above have been provided on a commodity contract-type basis, which may differ from their master netting arrangements classifications.

(b) Counterparties have the option to extend 5,000 Bbls per day of 2015 collar contracts with short puts for an additional year with a ceiling price of $100.08 per Bbl, a floor price of $90.00 per Bbl and a short put price of $80.00 per Bbl. These contracts give the counterparties the option to extend the contracts under the same terms for an additional year if the option to extend is exercised by the counterparties on December 31, 2015.

(c) The average forward NYMEX oil, gas and rollfactor prices are based on August 3, 2015 market quotes.

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(d) Represents swaps that fix the difference between (i) each day's price per Bbl of WTI for the first nearby month less (ii) the price per Bbl of WTI for the second nearby NYMEX month, multiplied by .6667; plus (iii) each day's price per Bbl of WTI for the first nearby month less (iv) the price per Bbl of WTI for the third nearby NYMEX month, multiplied by .3333.

(e) Forward component NGL prices are derived from respective active-market NGL component price quotes as of August 3, 2015.

(f) Subsequent to June 30, 2015, the Company entered into an additional (i) 1,000 Bbls per day of swap contracts for ethane forecasted for sale by the Company at Mont Belvieu, Texas-posted prices for 2016 with a fixed price of $8.93 per Bbl and (ii) 3,000 Bbls per day of swap contracts for propane forecasted for sale by the Company at Mont Belvieu, Texas-posted prices for 2016 with a fixed price of $20.76 per Bbl.

(g) Subsequent to June 30, 2015, the Company entered into an additional 40,000 MMBtu per day of 2016 collar contracts with short puts with a ceiling price of $3.71 per MMBtu, a floor price of $3.15 per MMBtu and a short put price of $2.75 per MMBtu.

(h) Represent swaps that fix the basis differentials between the index prices at which the Company sells its Gulf Coast, Mid-Continent and Permian Basin gas and the NYMEX Henry Hub index price used in gas swap and collar contracts.

(i) The average forward basis differential prices are based on August 3, 2015 market quotes for basis differentials between the relevant index prices and NYMEX-quoted forward prices.

(j) Represent swaps that fix the basis differentials between Permian Basin index prices and southern California index prices for Permian Basin gas forecasted for sale in southern California.

(k) Subsequent to June 30, 2015, the Company entered into gas index swap contracts for an additional 30,000 MMBtu per day of August 2015 gas with a price differential of $0.21 per MMBtu between Permian Basin index prices and southern California index prices.

(l) The average forward basis differential prices are based on August 3, 2015 market quotes for basis differentials between Permian Basin index prices and southern California index prices.

Marketing and basis differential derivatives. The Company enters into buy and sell marketing arrangements to fulfill firm pipeline transportation commitments. Associated with these marketing arrangements, the Company may enter into index swaps to mitigate price risk. As of June 30, 2015, the Company had marketing oil index swap contracts for 10,000 Bbl per day for the remainder of 2015 with a price differential of $2.99 per Bbl between Cushing WTI and LLS. As of June 30, 2015, these positions had an liability fair value of $1 million. Based on August 3, 2015 market quotes, the respective average forward basis differential price was $3.06 per Bbl between the relevant quoted forward oil index prices.

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. The Company's management, with the participation of its principal executive officer and principal financial officer, have evaluated, as required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the "Exchange Act"), the effectiveness of the Company's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of the end of the period covered by this Report. Based on that evaluation, the principal executive officer and principal financial officer concluded that the Company's disclosure controls and procedures were effective, as of the end of the period covered by this Report, in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, including that such information is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.
Changes in internal control over financial reporting. There have been no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the three months ended June 30, 2015 that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting.

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PART II. OTHER INFORMATION
Item 1. Legal Proceedings

The Company is party to various proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings and claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations.

Item 1A. Risk Factors
In addition to the information set forth in this Report, the risks that are discussed in the Company's Annual Report on Form 10-K for the year ended December 31, 2014, under the headings "Part I, Item 1. Business – Competition, Markets and Regulations," "Part I, Item 1A. Risk Factors" and "Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk," should be carefully considered as such risks could materially affect the Company's business, financial condition or future results. There has been no material change in the Company's risk factors from those described in the Annual Report on Form 10-K.
These risks are not the only risks facing the Company. Additional risks and uncertainties not currently known to the Company or that it currently deems to be immaterial also may have a material adverse effect on the Company's business, financial condition or future results.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds
Purchases of Equity Securities by the Issuer and Affiliated Purchasers
The following table summarizes the Company's purchases of treasury stock under plans or programs during the three months ended June 30, 2015:

Period	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs	Approximate Dollar Amount of Shares that May Yet Be Purchased under Plans or Programs
April 2015	2,914	$ 166.88	—	
May 2015	—	$ —	—	
June 2015	125	$ 148.69	—	
Total	3,039	$ 166.13	—	$ —

(a) Consists of shares purchased from employees in order for the employee to satisfy tax withholding payments related to share-based awards that vested during the period.

Item 4. Mine Safety Disclosures
The Company's sand mines are subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006. Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95.1 to this Quarterly Report filed on Form 10-Q.

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PIONEER NATURAL RESOURCES COMPANY

Item 6. Exhibits
Exhibits

Exhibit Number		Description
10.1	(a) —	Third Amendment to Pioneer USA 401(k) and Matching Plan dated May 13, 2015.
10.2	(a) —	Fourth Amendment to Pioneer USA 401(k) and Matching Plan dated July 7, 2015.
10.3	(a) —	Indemnification Agreement, dated June 29, 2015, between the Company and Mona K. Sutphen, together with a schedule identifying the other substantially identical agreement between the Company and Michael D. Wortley.
12.1	(a) —	Computation of Ratios of Earnings to Fixed Charges and Earnings to Fixed Charges and Preferred Stock Dividends.
31.1	(a) —	Chief Executive Officer certification under Section 302 of Sarbanes-Oxley Act of 2002.
31.2	(a) —	Chief Financial Officer certification under Section 302 of Sarbanes-Oxley Act of 2002.
32.1	(b) —	Chief Executive Officer certification under Section 906 of Sarbanes-Oxley Act of 2002.
32.2	(b) —	Chief Financial Officer certification under Section 906 of Sarbanes-Oxley Act of 2002.
95.1	(a) —	Mine Safety Disclosures.
101.INS	(a) —	XBRL Instance Document.
101.SCH	(a) —	XBRL Taxonomy Extension Schema.
101.CAL	(a) —	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	(a) —	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	(a) —	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	(a) —	XBRL Taxonomy Extension Presentation Linkbase Document.

(a) Filed herewith.
(b) Furnished herewith.

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PIONEER NATURAL RESOURCES COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned hereto duly authorized.

	PIONEER NATURAL RESOURCES COMPANY
Date: August 6, 2015	By: /s/ RICHARD P. DEALY Richard P. Dealy, Executive Vice President and Chief Financial Officer
Date: August 6, 2015	By: /s/ MARGARET M. MONTEMAYOR Margaret M. Montemayor, Vice President and Chief Accounting Officer

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101.LAB	(a) —	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	(a) —	XBRL Taxonomy Extension Presentation Linkbase Document.

(a) Filed herewith.
(b) Furnished herewith.