ALVARION LTD
Form 6-K
May 14, 2007

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

Form 6-K

REPORT OF FOREIGN PRIVATE ISSUER

PURSUANT TO RULE 13a-16 OR 15d-16
OF THE SECURITIES EXCHANGE ACT OF 1934

For the month of May 2007

Commission File Number: 0-30628

ALVARION LTD.
(Translation of registrant's name into English)

21A Habarzel Street, Tel Aviv 69710, Israel
(Address of principal executive office)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.
Form 20-F þ Form 40-F o

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1): ____

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): ____

Indicate by check mark whether by furnishing the information contained in this Form, the registrant is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.
Yes o No þ

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-___________

The following are included in this report on Form 6-K:

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, thereunto duly authorized.

ALVARION LTD.

Date: May 14th, 2007 By: /s/ Efrat Makov
Name: Efrat Makov

Title: CFO

EXHIBIT 1

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FOR IMMEDIATE RELEASE

Taiwanese High technology center chooses alvarion's 16e-based mobile wimax solution

4Motion to Provide Full Coverage to Industrial Technology Research Institute Campus in Hsinchu, Taiwan

Showcasing WiMAX/Wi-Fi Handover at Taipei International Convention Center Booth T2-1; Alvarion's Booth S8-1

Taipei Summit, Taiwan May 14, 2007— Alvarion Ltd. (NASDAQ: ALVR), the world's leading provider of WiMAX and wireless broadband solutions, today announced that the Industrial Technology Research Institute (ITRI) in Taiwan has chosen its Mobile WiMAX solution. Alvarion's 16e-based all-IP 4Motion™ OPEN™ WiMAX solution is designed to provide Mobile WiMAX services across the campus in Hsinchu, co-existing with Wi-Fi network. As a government-sponsored, primary R&D center for telecommunications industry in Taiwan, ITRI aims to develop cutting-edge technology and further innovate currently available technologies.

Building on prior successful WiMAX trials in the M-Taiwan project, such as with Chunghwa Telecom (CHT), Alvarion continues to contribute to the Taiwanese government's plan to provide ubiquitous broadband throughout the island nation. The main goals of the M-Taiwan initiative include elevating Taiwan to being one of the top five countries in the world for Internet penetration, while becoming one of the top ten countries in the world for low online access fees. In addition, the project is aimed at improving the broadband and wireless infrastructures in the country's remote areas to help bridge Taiwan's digital divide.

"After thorough market research and technology evaluation, we found Alvarion's 802.16e-based OPEN WiMAX solution to be a mature, advanced and stable one," said Dr. Gin-Kou Ma, Deputy General Director of SoC Technology Center (STC) in ITRI. "Alvarion has been very supportive of our R&D efforts, contributing with its professional and extensive knowledge in WiMAX."

The deployment will serve two purposes on the campus, both providing wireless services over WiMAX and allowing the institute to conduct Mobile WiMAX research.

After the network is deployed, Alvarion will provide professional technical assistance to aid the research and development of WiMAX services over the new network.

“We are delighted to work with ITRI and enable vendors to evaluate their products via our 4Motion solution, combining BreezeMAX™ and best-of-breed systems,” said Rudy Leser, corporate vice president strategy and marketing of Alvarion. “Being selected by ITRI proves once again our strong technology leadership. OPEN WiMAX’s operator-centric focus, open architecture and creation of a multi-vendor complete ecosystem will assist local Taiwanese manufacturers to become leaders in the growing WiMAX market."

About ITRI

The Industrial Technology Research Institute (ITRI) is a non-profit R&D organization engaging in applied research and technical services (www.itri.org.tw). Founded in 1973, ITRI has played a vital role in transforming Taiwan’s economy from a labor-intensive model to a high-tech industrial one. ITRI is a multidisciplinary research center. It has six core laboratories, five focus centers, five linkage centers, several business development units, and other supporting units. ITRI has 6,000 employees, and serves as the technical center for industry and an unofficial arm of the government's industrial policies in Taiwan. Backed by its broad research scope and close industrial ties, ITRI is becoming an increasingly active member in the global industrial R&D community. Apart from its headquarters located in Taiwan, ITRI has branch offices in Silicon Valley, Tokyo, Berlin, and Moscow.

About Alvarion

With more than 3 million units deployed in 150 countries, Alvarion (www.alvarion.com) is the world’s leading provider of innovative wireless broadband network solutions enabling Personal Broadband to improve lifestyles and productivity with portable and mobile data, VoIP, video and other services.
Alvarion is leading the market to Open WiMAX solutions with the most extensive deployments and proven product portfolio in the industry covering the full range of frequency bands with both fixed and mobile solutions. Alvarion’s products enable the delivery of personal mobile broadband, business and residential broadband access, corporate VPNs, toll quality telephony, mobile base station feeding, hotspot coverage extension, community interconnection, public safety communications, and mobile voice and data.
As a wireless broadband pioneer, Alvarion has been driving and delivering innovations for over 10 years from core technology developments to creating and promoting industry standards. Leveraging its key roles in the IEEE and HiperMAN standards committees and experience in deploying OFDM-based systems, the Company's prominent work in the WiMAX Forum is focused on increasing the widespread adoption of standards-based products in the wireless broadband market and leading the entire industry to Open WiMAX solutions.

This press release contains forward-looking statements within the meaning of the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. These statements are based on the current expectations or beliefs of Alvarion's management and are subject to a number of factors and uncertainties that could cause actual results to differ materially from those described in the forward-looking statements. The following factors, among others, could cause actual results to differ materially from those described in the forward-looking statements: the failure of the market for WIMAX products to develop as anticipated; Alvarion's inability to capture market share in the expected growth of the WIMAX market as anticipated, due to, among other things, competitive reasons or failure to execute in our sales, marketing or manufacturing objectives; inability to further identify, develop and achieve success for new products, services and technologies; increased competition and its effect on pricing, spending, third-party relationships and revenues; as well as the inability to establish and maintain relationships with commerce, advertising, marketing, and technology providers and other risks detailed from time to time in the Company's 20-F Annual Report Risk Factors section as well as in other filings with the Securities and Exchange Commission.

Information set forth in this press release pertaining to third parties has not been independently verified by Alvarion and is based solely on publicly available information or on information provided to Alvarion by such third parties for inclusion in this press release. The web sites appearing in this press release are not and will not be included or incorporated by reference in any filing made by Alvarion with the Securities and Exchange Commission, which this press release will be a part of.

You may request Alvarion's future press releases or a complete Investor Kit by contacting Esther Loewy, Investor Relations: esther.loewy@alvarion.com or +972.3.767.4476.

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2" style="vertical-align:bottom;padding-left:2px;padding-top:2px;padding-bottom:2px;">
(26
)
Income taxes payable

26

1

Other current liabilities

(28
)

(30
)
Net cash provided by operating activities

789

1,798

Cash flows from investing activities:

Proceeds from disposition of assets, net of cash sold

556

855

Additions to oil and gas properties

(1,573
)

(2,259
)
Additions to other assets and other property and equipment, net

(191
)

(224
)
Net cash used in investing activities

(1,208
)

(1,628
)
Cash flows from financing activities:

Borrowings under long-term debt

—

523

Principal payments on long-term debt

—

(523
)
Distributions to noncontrolling interests

(1
)

(1
)
Exercise of long-term incentive plan stock options and employee stock purchases

6

13

Purchases of treasury stock

(31
)

(33
)
Tax benefits related to stock-based compensation

10

14

Payments of financing fees

(3
)

—

Dividends paid

(6
)

(6
)
Net cash used in financing activities

(25
)

(13

)

Net increase (decrease) in cash and cash equivalents

(444
)

157

Cash and cash equivalents, beginning of period

1,025

393

Cash and cash equivalents, end of period

$
581

$
550

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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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 September 30, 2015 and for the three and nine months ended September 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. In connection therewith, during the three and nine months ended September 30, 2015, the Company recognized $9 million and $24 million, respectively, of restructuring charges in other expense in the accompanying consolidated statements of operations. The Company estimates that it will incur an additional $3 million of restructuring charges during the fourth quarter of 2015. The aggregate $27 million of estimated restructuring charges includes approximately $18 million in employee severance costs, $6 million in lease-related costs and $3 million in employee relocation and other costs.

Employee severance costs. The $18 million of employee severance costs is based on the number of employees impacted by the restructuring. Approximately $17 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 September 30, 2015, the Company had $4 million of restructuring liabilities related to employee severance costs and future lease obligations recorded in other current and noncurrent liabilities in the accompanying consolidated balance sheets.

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 or 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. In August 2015, the FASB issued ASU 2015-14, which defers the effective date of ASU 2014-09 for one year to annual reports beginning after December 15, 2017. Early adoption is permitted as of the original effective date, December 15, 2016. Entities have the option of using either a full retrospective or modified approach to adopt the new standards. 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 nine months ended September 30, 2015, the Company recorded net gains on disposition of assets in continuing operations of $779 million and $782 million, respectively, as compared to $1 million and $11 million for the same respective periods in 2014. The net gains attributable to the disposition of assets included the following:

- EFS Midstream. In November 2014, the Company announced that it was pursuing the divestment of its 50.1 percent equity interest in EFS Midstream LLC ("EFS Midstream"), which was accounted for under the equity method of accounting for investments in unconsolidated affiliates. In July 2015, the Company closed on the sale of its interest in EFS Midstream to an unaffiliated third party, 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. The amount to be received in July 2016, less imputed interest, is included in notes receivable in the accompanying consolidated balance sheets and represents a noncash investing activity. Associated with the sale, the Company recorded a pretax gain of $778 million during the third quarter of 2015.

- 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 nine months ended September 30, 2015, the Company incurred $10 million and $30 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 included its Hugoton, Barnett Shale and Pioneer Alaska results of operations in 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 nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Revenues and other income (a)	$—	$50	$1	$234
Costs and expenses (b)	(2)	(108)	(10)	(408)
Loss from discontinued operations before income taxes	(2)	(58)	(9)	(174)
Current tax provision	—	—	—	(1)
Deferred tax benefit	—	21	3	62
Loss from discontinued operations, net of tax	$(2)	$(37)	$(6)	$(113)

(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.

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

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 September 30, 2015 for each of the fair value hierarchy levels:

	Fair Value Measurement at September 30, 2015 Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1) (in millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value at September 30, 2015
Assets:				
Commodity derivatives	$—	$779	$—	$779
Deferred compensation plan assets	69	—	—	69
Total assets	69	779	—	848
Liabilities:				
Commodity derivatives	—	1	—	1
Interest rate derivatives	—	2	—	2
Total liabilities	—	3	—	3
Total recurring fair value measurements	$69	$776	$—	$845

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 September 30, 2015, the significant inputs to these asset values represented Level 1 independent active exchange market price inputs.

Interest rate derivatives. The Company's interest rate derivative liabilities represent Treasury rate swap contracts and interest rate swap contracts. The Company utilizes discounted cash flow models for valuing its interest rate derivatives. The net derivative values attributable to the Company's interest rate derivative contracts are based on (i) the contracted notional amounts, (ii) forward active market-quoted London Interbank Offered Rate ("LIBOR") or United States Treasury yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company's interest rate derivative fair value measurements represent Level 2 inputs in the hierarchy.

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 nine months ended September 30, 2015, the Company recorded charges in other expense in the Company's accompanying consolidated statements of operations of $12 million and $20 million, respectively, to reduce the carrying value of inventory to fair value.

PIONEER NATURAL RESOURCES COMPANY
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September 30, 2015
(Unaudited)

Proved oil and gas properties. During 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 and in the South Texas - Other field (Edwards dry gas). As a result of management's assessments, during March 2015 and September 2015, the Company recognized pretax noncash impairment charges to reduce the carrying values of the West Panhandle field and the South Texas - Other field, respectively, to their estimated fair values.

The Company calculated the fair values of the West Panhandle field and the South Texas - Other field using a discounted future cash flow model. Significant Level 3 assumptions associated with the calculations included Management's Price Outlooks and management's outlooks for (i) production costs, (ii) capital expenditures, (iii) production and (iv) 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.

The following table presents the fair value and fair value adjustments (in millions) for the Company's March 2015 and September 2015 proved property impairments, as well as the average oil price per barrel ("Bbl") and gas price per British thermal unit ("MMBtu") utilized in respective Management's Price Outlooks:

				Management's Price Outlooks	
		Fair Value	Fair Value Adjustment	Oil	Gas
West Panhandle	March 2015	$61	$(138)	$65.02	$3.83
South Texas - Other	September 2015	$88	$(72)	$57.41	$3.46

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 Hugoton field assets, the Barnett Shale field assets and Pioneer Alaska were classified as held for sale and carried as such until their divestitures in September 2014, September 2014 and April 2014, respectively. Associated therewith, the Company recognized impairment charges during 2014 to reduce the carrying values of the Hugoton field assets, the Barnett Shale field assets and Pioneer Alaska to their sales prices, less costs to sell.

The following table presents the fair value adjustments made by the Company during 2014 related to assets associated with divestitures:

		Fair Value Adjustment	
	Sales Value Less Costs to Sell	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
	(in millions)		
Hugoton field	$328	$(34)	$(34)
Barnett Shale field	$149	$(46)	$(174)
Pioneer Alaska	$253	$—	$(97)

See Note C for additional information regarding the Company's divestitures of the Hugoton field assets, 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 accompanying consolidated balance sheets as of September 30, 2015 and December 31, 2014 are as follows:

	September 30, 2015		December 31, 2014	
	Carrying	Fair	Carrying	Fair

	Value (in millions)	Value	Value	Value
Long-term debt	$2,675	$2,867	$2,665	$2,938

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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, accounts receivables, prepaid expenses, notes receivable, 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 September 30, 2015 and the weighted average oil prices for those contracts:

	Three Months Ending December 31,	Year Ending December 31,	
	2015	2016	2017
Swap contracts:			
Volume (Bbl)	82,000	4,475	—
Price per Bbl	$71.18	$59.00	$—
Collar contracts with short puts (a):			
Volume (Bbl)	15,000	101,806	34,000
Price per Bbl:			
Ceiling	$97.69	$75.93	$70.42
Floor	$82.97	$65.30	$57.65
Short put	$69.67	$46.08	$47.65
Rollfactor swap contracts (b):			
Volume (Bbl)	37,000	—	—
NYMEX roll price	$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 NGL component product prices.

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

	Three Months Ending December 31,	Year Ending December 31,
	2015	2016
Ethane swap contracts:		
Volume (Bbl)	6,000	5,000
Price per Bbl	$7.80	$11.61
Propane swap contracts:		
Volume (Bbl)	11,000	7,500
Price per Bbl	$21.62	$21.57

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.

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PIONEER NATURAL RESOURCES COMPANY
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September 30, 2015
(Unaudited)

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

	Three 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)	285,000	180,000	—
Price per MMBtu:			
Ceiling	$5.07	$4.01	$—
Floor	$4.00	$3.24	$—
Short put	$3.00	$2.78	$—
Basis swap contracts:			
Gulf Coast index swap volume (a)	20,000	10,000	—
Price differential ($/MMBtu)	$—	$—	$—
Mid-Continent index swap volume (a)	95,000	15,000	45,000
Price differential ($/MMBtu)	$(0.24)	$(0.32)	$(0.32)
Permian Basin index swap volume (a)	10,000	—	—
Price differential ($/MMBtu)	$(0.13)	$—	$—
Permian Basin index swap volume (b)	30,000	—	—
Price differential ($/MMBtu)	$0.19	$—	$—

(a) 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 HH index price used in gas swap and collar contracts.
(b) 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.

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 September 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 WTI and Louisiana Light Sweet oil.

Interest rate derivative activities. As of September 30, 2015, the Company was party to interest rate derivative contracts whereby the Company will receive (i) the 10-year Treasury rate in exchange for paying average fixed rates of 2.15 percent on a notional amount of $100 million on December 15, 2015 and 2.24 percent on a notional amount of $100 million on March 15, 2016 and (ii) the three-month LIBOR rate for the 10-year period from March 2016 through March 2026 in exchange for paying a fixed interest rate of 2.18 percent on a notional amount of $50 million on March 15, 2016. Subsequent to September 30, 2015, the Company entered into additional interest rate derivative contracts whereby the Company will receive the three-month LIBOR rate for the 10-year period from March 2016 through March 2026 in exchange for paying a fixed interest rate of 2.12 percent on a notional amount of $50 million on March 15, 2016.

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.

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The aggregate fair value of the Company's derivative instruments reported in the accompanying 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 September 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	$634	$(2)	$632
Commodity price derivatives	Derivatives - noncurrent	$148	$(1)	147
				$779
Liability Derivatives:				
Commodity price derivatives	Derivatives - current	$2	$(2)	$—
Interest rate derivatives	Derivatives - current	$2	$—	2
Commodity price derivatives	Derivatives - noncurrent	$2	$(1)	1
				$3

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 September 30,		Nine Months Ended September 30,	
		2015	2014	2015	2014
		(in millions)			
Commodity price derivatives	Derivative gains, net	$575	$341	$614	$1
Interest rate derivatives	Derivative gains, net	(2)	—	3	18
Total		$573	$341	$617	$19

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 nine months ended September 30, 2015:

	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2015
	(in millions)	
Beginning capitalized exploratory costs	$270	$305
Additions to exploratory costs pending the determination of proved reserves	321	782
Reclassification due to determination of proved reserves	(319)	(800)
Exploratory well costs charged to exploration expense	—	(15)
Ending capitalized exploratory costs	$272	$272

As of September 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

Credit facility. The Company's long-term debt consists of senior notes, a revolving corporate credit facility and the effects of net deferred fair value hedge losses and issuance discounts. During August 2015, the Company entered into the Second Amendment to its Second Amended and Restated 5-Year Revolving Credit Agreement ("Credit Facility") with a syndicate of financial institutions to primarily extend the maturity of the credit facility from December 2017 to August 2020 while maintaining aggregate loan commitments of $1.5 billion. The Company accounted for the entry into the Credit Facility as a modification of the prior agreement and capitalized the debt issuance costs along with those unamortized issuance costs that remained from the issuance of the prior agreement. As of September 30, 2015, the Company had no outstanding borrowings under the Credit Facility and was in compliance with its debt covenants.

Senior notes. The Company's 5.875% senior notes (the "5.875% Senior Notes"), with outstanding debt principal balances of $455 million, are due to mature in July 2016. As the Company has the ability to fund any required cash payments upon the maturity of the 5.875% Senior Notes with its borrowing capacity under the Credit Facility, to the extent that they are not refinanced prior to their maturity, such notes are classified as long-term debt in the accompanying consolidated balance sheets.

NOTE H. Incentive Plans

Stock-based compensation

For the three and nine months ended September 30, 2015, the Company recorded $26 million and $87 million, respectively, of stock-based compensation expense for all plans, as compared to $27 million and $89 million for the same respective periods

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of 2014. As of September 30, 2015, there was $131 million of unrecognized compensation expense related to unvested share-based compensation plan awards, including $21 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 September 30, 2015 and December 31, 2014, accounts payable – due to affiliates includes $11 million and $23 million, respectively, of liabilities attributable to Liability Awards.

The following table summarizes the activity that occurred during the nine months ended September 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	439,742	158,726	82,431	—
Awards vested	(525,494)	(185,302)	—	—
Awards forfeited	(36,679)	(28,851)	—	—
Outstanding as of September 30, 2015	1,111,108	272,660	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 nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Beginning asset retirement obligations	$ 187	$ 193	$ 189	$ 194
New wells placed on production	1	1	2	3
Changes in estimates	—	2	—	3
Dispositions	—	(5)	—	(7)
Liabilities settled	(9)	(6)	(18)	(14)
Accretion of discount	3	3	9	9
Ending asset retirement obligations	$ 182	$ 188	$ 182	$ 188

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 September 30, 2015, the current portion of the Company's asset retirement obligations was $31 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

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not believe these obligations are probable of having a material impact on its liquidity, financial position or future results of operations.

NOTE K. Interest and Other Income

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Equity interest in income of EFS Midstream (a)	$—	$3	$5	$10
Deferred compensation plan income	—	—	4	3
Interest income	2	—	2	—
Loss from vertical integration services (b)	(20)	(2)	(16)	(9)
Other income	1	1	5	5
Total interest and other income	$(17)	$2	$—	$9

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

(b) 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 nine months ended September 30, 2015, these vertical integration net margins included $66 million and $264 million, respectively, of revenues and $86 million and $280 million, respectively, of costs and expenses. For the same periods in 2014, these vertical integration net margins included $125 million and $321 million, respectively, of revenues and $127 million and $330 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 nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Idle drilling and well service equipment charges (a)	$22	$2	$73	$2
Transportation commitment charge (b)	11	11	38	34
Restructuring charges (c)	9	—	24	—
Impairment of inventory and other property and equipment (d)	13	3	21	7
Other	5	4	14	12
Total other expense	$60	$20	$170	$55

(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 associated with the Company's restructuring of 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) Primarily 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 nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Current tax benefit (provision)	$ (48)	$ 14	$ (49)	$ (4)
Deferred tax provision	(307)	(250)	(146)	(315)
Income tax provision	$ (355)	$ (236)	$ (195)	$ (319)

For both the three and nine months ended September 30, 2015, the Company's effective tax rate, excluding income attributable to noncontrolling interests, was 35 percent, as compared to effective rates of 36 percent and 34 percent for the same respective periods in 2014. During 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 nine months ended September 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 sand mine acquisition. The Company has no unrecognized tax benefits as of September 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 2013 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 September 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 Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Income from continuing operations	$ 648	$ 411	$ 356	$ 612
Participating basic earnings	(6)	(4)	(3)	(5)
Basic and diluted income from continuing operations	$ 642	$ 407	353	607
Basic and diluted loss from discontinued operations	$ (2)	$ (37)	$ (6)	$ (113)
Basic and diluted net income attributable to common stockholders	$ 640	$ 370	$ 347	$ 494

Basic weighted average common shares outstanding were 149 million for both the three and nine months ended September 30, 2015 and diluted weighted average common shares outstanding were 150 million and 149 million for the three and nine months ended September 30, 2015, respectively. Basic and diluted weighted average common shares outstanding were 143 million for the three and nine months ended September 30, 2014.

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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 third quarter of 2015 included the following highlights:

- Net income attributable to common stockholders for the third quarter of 2015 was $646 million ($4.27 per diluted share), as compared to net income of $374 million ($2.58 per diluted share) for the third quarter of 2014. The increase in net income attributable to common stockholders is comprised of a $237 million increase in income from continuing operations attributable to common stockholders and a $35 million decrease in loss from discontinued operations, net of tax.

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

- the recognition of a $778 million gain on disposition of assets as a result of the sale of EFS Midstream in July 2015; and
- a $232 million increase in net derivative gains, primarily as a result of declines in forward commodity prices and the Company's portfolio of derivatives; partially offset by
- a $410 million decrease in oil and gas revenues as a result of a 49 percent decrease in the average commodity prices per BOE, partially offset by a 13 percent increase in sales volumes;
- a $90 million increase in DD&A expense, primarily attributable to the 13 percent increase in sales volumes and reductions in proved reserves as a result of the decline in commodity prices;
- a $72 million noncash impairment charge related to the Company's South Texas - Other field in the third quarter of 2015;
- a $40 million increase in other expense, primarily related to idle drilling rig charges, inventory valuation allowances and restructuring charges associated with the closing of the Company's Denver, Colorado office;
- a $21 million decrease in net margins attributable to purchases and sales of oil and gas used to fulfill transportation commitments;
- a $19 million decrease in interest and other income, primarily attributable to decreased fracture stimulation service margins, reflecting a reduction in market rates for such services as a result of lower commodity prices; and
- a $119 million increase in the Company's income tax provision as a result of the Company's increase in income from continuing operations before taxes.

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

- During the third quarter of 2015, average daily sales volumes from continuing operations increased by 13 percent to 210,711 BOEPD, as compared to 186,077 BOEPD during the third quarter of 2014. The increase in third quarter 2015 average daily sales volumes, as compared to the third quarter of 2014, is primarily due to the Company's successful Spraberry/Wolfcamp horizontal drilling program.
- Average oil, NGL and gas prices decreased during the third quarter of 2015 to $42.46 per Bbl, $12.39 per Bbl and $2.53 per Mcf, respectively, as compared to $90.82 per Bbl, $28.44 per Bbl and $3.79 per Mcf, respectively, in the third quarter of 2014.
- Net cash provided by operating activities decreased to $358 million for the three months ended September 30, 2015, as compared to $616 million for the three months ended September 30, 2014. The $258 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 September 30, 2015, the Company's net debt to book capitalization increased to 19 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 oversupply 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 OPEC oil production increases as part of an effort to retain market share combined with only modest demand growth in the United States and decreasing demand in other parts of the world, particularly

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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 supply and demand balance and the overhang in storage levels begins to decline, prices are expected to remain under pressure. In addition, the expected 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, fracture-stimulation services and oilfield supplies, 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 nine months 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 25 percent decrease in drilling and completion costs compared to 2014 and (ii) an 18 percent reduction in third 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.

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. To-date, the Company has added eight horizontal rigs since July 1, 2015. The Company does not expect to add any additional drilling rigs during the remainder of 2015 based on the Company's outlook for commodity prices and continuing efficiency improvements, which are significantly reducing the number of days required to place wells on production. This additional drilling activity, combined with the efficiency improvements, 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.

Fourth Quarter 2015 Outlook

Based on current estimates, the Company expects the following operating and financial results from continuing operations for the quarter ending December 31, 2015:

Production is forecasted to average 206,000 to 211,000 BOEPD.

Production costs (including production and ad valorem taxes and transportation costs) are expected to average $11.00 to $13.00 per BOE based on current NYMEX strip commodity prices. DD&A expense is expected to average $18.50 to $20.50 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 $40 million to $50 million, excluding anticipated nonrecurring restructuring charges during the quarter of approximately $3 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 $10 million to $20 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 nine months ended September 30, 2015:

	Oil (Bbls)	NGLs (Bbls)	Gas (Mcf)	Total (BOE)
Permian Basin	79,988	22,836	111,847	121,464
South Texas - Eagle Ford Shale	18,063	11,531	94,422	45,331
Raton Basin	—	—	113,325	18,887
West Panhandle	2,924	3,360	14,304	8,669
South Texas - Other	1,803	175	24,666	6,089
Other	2	1	30	8
Total	102,780	37,903	358,594	200,448

The Company's total liquids production from continuing operations increased to 70 percent of total production, on a BOE basis, for the nine months ended September 30, 2015, as compared to 68 percent for the same period last year.
The following table summarizes by geographic area the Company's finding and development costs incurred during the nine months ended September 30, 2015:

	Acquisition Costs		Exploration	Development	
	Proved	Unproved	Costs	Costs	Total
	(in millions)				
Permian Basin	$9	$24	$627	$468	$1,128
South Texas - Eagle Ford Shale	—	—	191	133	324
Raton Basin	—	—	2	2	4
West Panhandle	—	—	1	8	9
South Texas - Other	—	—	1	—	1
Other	—	—	10	—	10
Total	9	$24	$832	$611	$1,476

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

	Development Drilling			
	Beginning Wells in Progress	Wells Spud	Successful Wells	Ending Wells in Progress
Permian Basin	41	48	72	17
South Texas - Eagle Ford Shale	13	25	29	9
Total	54	73	101	26

	Exploration/Extension Drilling				
	Beginning Wells in Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells in Progress
Permian Basin	75	82	97	—	60
South Texas - Eagle Ford Shale	30	53	58	1	24
Other	1	—	—	1	—
Total	106	135	155	2	84

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. To-date, the Company has added eight horizontal rigs since July 1, 2015. The Company does not expect to add any additional drilling rigs during the remainder of 2015 based on the Company's outlook for commodity prices and continuing efficiency improvements, which are significantly reducing the number of days required to place wells on production. During 2015, the Company expects to drill approximately 195 horizontal wells (110 horizontal wells in the northern portion of the play and 85 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 three quarters of 2015, the Company successfully completed 169 wells in the Permian Basin area, including 148 horizontal wells and 21 vertical wells, with the vertical wells primarily being wells carried over from 2014 and placed on production in 2015.

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 317,000 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. An approximate 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 new tank batteries and saltwater disposal systems, with efforts underway to achieve further cost reductions. By early 2016, costs for new 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 spend $390 million of drilling capital in 2015 to drill approximately 100 horizontal wells in the Eagle Ford Shale. 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 88 horizontal Eagle Ford Shale wells during the first nine months of 2015, 87 of which were successful, with average lateral lengths of approximately 5,500 feet and, on average, 20-stage fracture stimulations. The Company has placed 48 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.

Eagle Ford Shale production in 2015 has been negatively impacted by well performance issues resulting from well completion design changes (primarily reduced fluid level concentrations) that were made early in 2015 to reduce costs. Future completions will use higher fluid level concentration in an effort to return well performance back to historical levels. The Company plans to also test higher proppant concentration, shorter stage lengths and tighter cluster spacing.

During November 2014, the Company announced that it was pursuing the divestment of its 50.1 percent equity interest in EFS Midstream. In July 2015, the Company closed on the sale of its interest in EFS Midstream to an unaffiliated third party, 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 recorded a pretax gain of $778 million during the third quarter of 2015. As a result of the sale, the Company no longer receives its share of the cash flow generated by EFS Midstream, which had the effect of increasing the Company's third-party transportation component of oil and gas production

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costs by approximately $0.75 per BOE. In conjunction with this transaction, the Company also extended its downstream processing and transportation contracts to 20 years, with improved terms.

Results of Operations from Continuing Operations

Oil and gas revenues. Oil and gas revenues totaled $557 million and $1.7 billion for the three and nine months ended September 30, 2015, respectively, as compared to $967 million and $2.8 billion for the same respective periods in 2014.

The decrease in oil and gas revenues during the three months ended September 30, 2015, as compared to the same period in 2014, is primarily due to declines of 53 percent, 56 percent and 33 percent in average oil, NGL and gas prices, respectively, partially offset by 23 percent, five percent and five percent increases in daily oil, NGL and gas sales volumes, respectively. The decrease in oil and gas revenues during the nine months ended September 30, 2015, as compared to the same period in 2014, is primarily due to declines of 51 percent, 55 percent and 41 percent in average oil, NGL and gas prices, respectively, partially offset by 25 percent, two percent and six percent increases in daily oil, NGL and gas sales volumes, respectively.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Oil (Bbls)	109,101	88,973	102,780	82,485
NGLs (Bbls)	41,617	39,819	37,903	37,319
Gas (Mcf)	359,957	343,711	358,594	336,749
Total (BOEs)	210,711	186,077	200,448	175,929

Average daily BOE sales volumes increased by 13 percent and 14 percent for the three and nine months ended September 30, 2015, respectively, as compared to the same periods in 2014, principally due to the Company's successful Spraberry/Wolfcamp horizontal drilling program. Production for the nine months ended September 30, 2015 reflects lower NGL production volumes of approximately 5,200 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 nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Oil (per Bbl)	$42.46	$90.82	$45.63	$92.94
NGL (per Bbl)	$12.39	$28.44	$13.72	$30.36
Gas (per Mcf)	$2.53	$3.79	$2.53	$4.28
Total (per BOE)	$28.75	$56.51	$30.52	$58.20

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. The net effect of third party purchases and sales of oil and gas for the three and nine months ended September 30, 2015 was a loss of $13 million and $19 million, respectively, as compared to income of $8 million and $19 million for the same respective periods in 2014. See Note L of Notes to Consolidated Financial Statements included in "Item 1. Financial

Statements" for further information on transportation commitment charges.

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Interest and other income. Interest and other income for the three and nine months ended September 30, 2015 was a loss of $17 million and nil, respectively, as compared to income of $2 million and $9 million for the same respective periods in 2014. The decrease in interest and other income for both the three and nine months ended September 30, 2015, as compared to the same respective periods in 2014, is primarily due to a decrease 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 nine months ended September 30, 2015, the Company recorded $573 million and $617 million of net derivative gains, respectively, on commodity price and interest rate derivatives, of which $238 million and $595 million represented net cash receipts, respectively. During the three and nine months ended September 30, 2014, the Company recorded $341 million and $19 million of net derivative gains, respectively, of which $3 million represented net cash receipts and $20 million represented 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 nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30, 2015			Nine Months Ended September 30, 2015		
	Net cash receipts (in millions)	Price impact		Net cash receipts (in millions)	Price impact	
Oil derivative receipts	$205	$20.47	per Bbl	$505	$17.98	per Bbl
NGL derivative receipts	5	$1.28	per Bbl	7	$0.65	per Bbl
Gas derivative receipts	29	$0.87	per Mcf	85	$0.87	per Mcf
Total net commodity derivative receipts	$239			$597		

	Three Months Ended September 30, 2014			Nine Months Ended September 30, 2014		
	Net cash receipts (payments) (in millions)	Price impact		Net cash receipts (payments) (in millions)	Price impact	
Oil derivative receipts (payments)	$1	$0.14	per Bbl	$(13)	$(0.49)	per Bbl
NGL derivative receipts	2	$0.48	per Bbl	3	$0.26	per Bbl
Gas derivative payments	—	$—	per Mcf	(29)	$(0.32)	per Mcf
Total net commodity derivative payments	$3			$(39)		

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 $779 million and $782 million for the three and nine months ended September 30, 2015, respectively, as compared to $1 million and $11 million for the same respective periods in 2014. The net gains on the disposition of assets for the three and nine months ended September 30, 2015 are primarily due to the gain of $778 million recorded on the sale of EFS Midstream in July 2015. 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 $189 million and $532 million during the three and nine months ended September 30, 2015, respectively, as compared to $168 million and $493 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.

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Total oil and gas production costs per BOE for the three and nine months ended September 30, 2015 decreased by one percent and five percent, as compared to the same respective periods in 2014. The decrease in lease operating expenses per BOE during the three and nine months ended September 30, 2015, as compared to the same respective periods in 2014, is primarily due to a greater proportion of the Company's production coming from horizontal wells in Spraberry/Wolfcamp area that have lower per BOE lease operating costs, cost reduction initiatives and lower electricity and fuel costs, which are impacted by lower commodity prices. The increase in third-party transportation charges reflects the Company no longer receiving cash flow generated by EFS Midstream as a result of its sale in July 2015. The increase in net natural gas plant charges per BOE during the three and nine months ended September 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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Lease operating expenses	$6.82	$7.83	$7.15	$8.19
Third-party transportation charges	2.30	1.66	1.82	1.75
Net natural gas plant charges	(0.01)	(0.30)	0.12	(0.33)
Workover costs	0.64	0.63	0.63	0.66
Total production costs	$9.75	$9.82	$9.72	$10.27

Production and ad valorem taxes. The Company's production and ad valorem taxes were $36 million and $112 million during the three and nine months ended September 30, 2015, respectively, as compared to $58 million and $169 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 nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Production taxes	1.11	2.42	$1.23	$2.35
Ad valorem taxes	$0.76	$0.93	0.82	1.16
Total production and ad valorem taxes	$1.87	$3.35	$2.05	$3.51

Depletion, depreciation and amortization expense. The Company's DD&A expense was $364 million ($18.77 per BOE) and $1.0 billion ($18.32 per BOE) for the three and nine months ended September 30, 2015, respectively, as compared to $274 million ($16.03 per BOE) and $734 million ($15.28 per BOE) during the same respective periods in 2014. The change in per BOE DD&A expense during the three and nine months ended September 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 $18.22 and $17.72 per BOE during the three and nine months ended September 30, 2015, respectively, as compared to $15.48 and $14.72 per BOE during the same respective periods in 2014. The change in per BOE depletion expense during the three and nine months ended September 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 declines in commodity prices during 2015 that led to a reduction in 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 costs and capital costs associated with these fields. All inputs to the cash flow model must be evaluated at each measurement date.

During 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 and in the South Texas - Other field. As a result of management's assessments, during March 2015 and September 2015, the Company recognized pretax noncash impairment charges of $138 million and $72 million to reduce the carrying values of the West Panhandle field and the South Texas - Other field, respectively, to their estimated fair values. The Company's estimates of undiscounted future net cash flows attributable to the Company's other oil and gas properties on September 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 nine months ended September 30, 2015 and 2014 (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Geological and geophysical	$18	$21	$56	$69
Exploratory dry holes	—	1	16	5
Leasehold abandonments and other	7	—	7	6
	$25	$22	$79	$80

The Company's geological and geophysical costs decreased by $3 million and $13 million during the three and nine months ended September 30, 2015, as compared to the same respective periods in 2014, primarily due to decreased seismic and seismic interpretation expenditures. During the nine months ended September 30, 2015, the Company incurred exploratory dry hole expense and leasehold abandonments primarily related to unsuccessful exploration wells and abandonment of unproved properties in eastern Colorado.

During the nine months ended September 30, 2015, the Company drilled and evaluated 157 exploration/extension wells, 155 of which were successfully completed as discoveries. During the same period in 2014, the Company drilled and evaluated 241 exploration/extension wells, 240 of which were successfully completed as discoveries.

General and administrative expense. General and administrative expense for the three and nine months ended September 30, 2015 was $81 million and $246 million ($4.18 per BOE and $4.50 per BOE), respectively, as compared to $81 million and $244 million ($4.72 per BOE and $5.08 per BOE) 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 $9 million for both the three and nine months ended September 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 $138 million for both the three and nine months ended September 30, 2015, and 2014. The weighted average interest rate on the Company's indebtedness for both the three and nine months ended September 30, 2015, including the effects of capitalized interest, was 6.6 percent, as compared to 6.6 percent and 6.3 percent for the same respective periods in 2014.

Other expense. Other expense was $60 million and $170 million for the three and nine months ended September 30, 2015, respectively, as compared to $20 million and $55 million during the same respective periods in 2014. The increase in other expense for the three and nine months ended September 30, 2015, as compared to the same respective periods in 2014, is primarily due to (i) increases of $20 million and $71 million, respectively, in idle drilling and well service equipment charges, (ii) increases of $10 million and $14 million, respectively, in inventory valuation allowances and other property and equipment impairments and (iii) restructuring charges of $9 million and

$24 million, respectively (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. In connection therewith, during the three and nine months ended September 30, 2015, the Company recognized $9 million and $24 million, respectively, of restructuring charges in other expense in the accompanying consolidated statements of operations. The Company estimates that it will incur an additional $3 million of restructuring charges during the fourth quarter of 2015. The aggregate $27 million of estimated restructuring charges includes approximately $18 million in employee severance costs, $6 million in lease-related costs and $3 million in employee relocation and other costs.

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

Income tax provision. The Company recorded income tax provisions from continuing operations of $355 million and $195 million for the three and nine months ended September 30, 2015, respectively, as compared to income tax provisions of $236 million and $319 million for the same respective periods in 2014. The Company's effective tax rate for both the three and nine months ended September 30, 2015 was 35 percent as compared to 36 percent and 34 percent for the same respective periods in 2014. The difference between the effective tax rate and the statutory tax rate during the nine months ended September 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 sand mine acquisition. 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 $2 million and $6 million for the three and nine months ended September 30, 2015, respectively, as compared to losses from discontinued operations, net of tax, of $37 million and $113 million for the same respective periods in 2014. The decrease in loss from discontinued operations for the three and nine months ended September 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's capital budget for 2015 is $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 nine months ended September 30, 2015 were $1.6 billion, consisting of $1.4 billion for drilling operations (excluding acquisitions, asset retirement obligations, capitalized interest and geological and geophysical administrative costs) and $166 million for buildings, vertical integration and other plant and equipment additions. Based on results for the nine months ended September 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 nine months ended September 30, 2015, as compared to $1.6 billion of cash used in investing activities during the nine months ended September 30, 2014. The decrease in cash used in investing activities for the nine months ended September 30, 2015, as compared to the nine months ended September 30, 2014, is primarily due to (i) a $686 million decrease in additions to oil and gas properties, (ii) a $33 million decrease in additions to other assets, partially offset by (iii) a $299 million decrease in proceeds from the disposition of assets. During the nine months ended September 30, 2015, the Company's expenditures for investing activities were primarily funded by net cash provided by operating activities, proceeds from asset dispositions and cash on hand.

Dividends/distributions. During March and August of 2015 and February and August 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 September 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. In the third quarter of 2015, there were no material changes to the Company's contractual obligations.

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 September 30, 2015, these contracts represented net assets of $776 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 September 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. During August 2015, the Company entered into a Second Amendment to its Second Amended and Restated 5-Year Revolving Credit Agreement, which primarily extended the maturity of the credit facility from December 2017 to August 2020. The Company has the ability to fund 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) with the borrowing capacity under the Credit Facility, but intends to refinance the notes prior to their maturity, subject to market conditions.

Operating activities. Net cash provided by operating activities during the nine months ended September 30, 2015 was $789 million, as compared to $1.8 billion during the same period in 2014. The decrease in net cash provided by operating activities for the nine months ended September 30, 2015, as compared to the nine months ended September 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 nine months ended September 30, 2015, the Company completed the sale of EFS Midstream for total consideration of $1.0 billion, of which $530 million was received at closing. The remaining approximately $500 million, will be received in July 2016. During the nine months ended September 30, 2014, the Company completed the sale of (i) the Company's Barnett Shale field net assets for cash proceeds of $150 million, (ii) the Company's Hugoton field net assets for cash proceeds of $328 million, (iii) Pioneer Alaska for cash proceeds of $267 million, (iv) Sendero for cash proceeds of $31 million (Sendero had $14 million of cash on hand at the time of the sale) and (v) 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 nine months ended September 30, 2015 was $25 million, as compared to net cash used in financing activities of $13 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 September 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 September 30, 2015. The Company also had cash on hand of $581 million as of September 30, 2015. If internal cash flows 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

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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 September 30, 2015 was $11.1 billion, consisting of $581 million of cash and cash equivalents, debt of $2.7 billion and equity of $9.0 billion. The Company's net debt to net book capitalization increased to 19 percent at September 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 $444 million. The Company's ratio of current assets to current liabilities increased to 2.10 to 1.00 at September 30, 2015, as compared to 1.49 to 1.00 at December 31, 2014, primarily due to the $497 million current note receivable associated with the sale of EFS Midstream and the aforementioned decrease in accounts payable.

New accounting pronouncements. The effects of new accounting pronouncements are discussed in Note B of Notes to Consolidated Financial Statements included in "Item 1. 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 nine months ending September 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	614	3	617
Contract maturity receipts	(593)	—	(593)
Contract termination receipts	—	(2)	(2)
Fair value of contracts outstanding as of September 30, 2015	$778	$(2)	$776

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.

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The following table provides information about financial instruments to which the Company was a party as of September 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 September 30, 2015. Although the Company had no outstanding variable rate debt as of September 30, 2015, the average variable contractual rates for its credit facility projected forward proportionate to the forward yield curve for LIBOR on October 30, 2015 is presented in the table below.

	Three Months Ending December 31, 2015	Year Ending December 31, 2016	2017	2018	2019	Thereafter	Total	Liability Fair Value at September 30, 2015
	(dollars in millions)							
Total Debt:								
Fixed rate principal maturities (a)	$—	$455	$485	$450	$—	$1,300	$2,690	$2,867
Weighted average fixed interest rate	6.15 %	6.17 %	6.11 %	5.91 %	5.80 %	5.81 %		
Average variable interest rate	1.91 %	2.27 %	2.85 %	3.31 %	3.67 %	3.97 %		
Interest Rate Swaps:								
Notional debt amount (b)	$100	$100	$—	$—	$—	$—		$2
Weighted average fixed rate payable (%)	2.15 %	2.24 %						
Variable rate receivable (%)	2.06 %	2.06 %						
Notional debt amount (c)	$—	$50	$—	$—	$—	$—		$—
Fixed rate payable (%)		2.18 %						
Variable rate receivable (%)		2.06 %						

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

(b) As of September 30, 2015, the Company was a party to interest rate derivative contracts whereby the Company will receive the 10-year Treasury rate in exchange for paying average fixed rates of 2.15 percent on a notional amount of $100 million on December 15, 2015 and 2.24 percent on a notional amount of $100 million on March 15, 2016.

(c) As of September 30, 2015, the Company was a party to interest rate derivative contracts whereby the Company will receive the three-month LIBOR rate for the 10-year period from March 2016 through March 2026 in exchange for paying a fixed interest rate of 2.18 percent on a notional amount of $50 million on March 15, 2016. Subsequent to September 30, 2015, the Company entered into additional interest rate derivative contracts whereby the Company will receive the three-month LIBOR rate for the 10-year period from March 2016 through March 2026 in exchange for paying a fixed interest rate of 2.12 percent on a notional amount of $50 million on March 15, 2016.

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 September 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.

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PIONEER NATURAL RESOURCES COMPANY

	Three Months Ending December 31, 2015	Year Ending December 31, 2016	2017	Asset (Liability) Fair Value at September 30, 2015 (a) (in millions)
Oil Derivatives:				
Average daily notional Bbl volumes:				
Swap contracts	82,000	4,475	—	$209
Weighted average fixed price per Bbl	$71.18	$59.00	$—	
Collar contracts with short puts (b)	15,000	101,806	34,000	$478
Weighted average ceiling price per Bbl	$97.69	$75.93	$70.42	
Weighted average floor price per Bbl	$82.97	$65.30	$57.65	
Weighted average short put price per Bbl	$69.67	$46.08	$47.65	
Average forward NYMEX oil prices (c)	$46.59	$50.23	$53.61	
Rollfactor swap contracts (d)	37,000	—	—	$3
Weighted average fixed price per Bbl	$0.06	$—	$—	
Average forward NYMEX rollfactor prices (c)	$(1.14)	$—	$—	
NGL Derivatives:				
Average daily notional Bbl volumes:				
Ethane swap contracts	6,000	5,000	—	$5
Weighted average fixed price per Bbl	$7.80	$11.61	$—	
Average forward ethane prices (e)	$7.77	$7.97	$—	
Propane swap contracts	11,000	7,500	—	$8
Weighted average fixed price per Bbl	$21.62	$21.57	$—	
Average forward propane prices (e)	$18.80	$19.56	$—	
Gas Derivatives:				
Average daily notional MMBtu volumes:				
Swap contracts	20,000	70,000	—	$35
Weighted average fixed price per MMBtu	$4.31	$4.06	$—	
Collar contracts with short puts	285,000	180,000	—	$42
Weighted average ceiling price per MMBtu	$5.07	$4.01	$—	
Weighted average floor price per MMBtu	$4.00	$3.24	$—	
Weighted average short put price per MMBtu	$3.00	$2.78	$—	
Average forward NYMEX gas prices (c)	$2.32	$2.57	$—	
Basis swap contracts:				$(2)
Gulf Coast index swap contracts (f)	20,000	10,000	—	
Weighted average fixed price per MMBtu	$—	$—	$—	
Mid-Continent index swap contracts (f)	95,000	15,000	45,000	
Weighted average fixed price per MMBtu	$(0.24)	$(0.32)	$(0.32)	
Permian Basin index swap contracts (f)	10,000	—	—	
Weighted average fixed price per MMBtu	$(0.13)	$—	$—	
Weighted average forward basis differential prices (g)	$(0.07)	$(0.15)	$(0.24)	
Permian Basin index swap contracts (h)	30,000	—	—	
Weighted average fixed price per MMBtu	$0.19	$—	$—	
Weighted average forward basis differential prices (i)	$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 October 30, 2015 market quotes.

(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 October 30, 2015.

(f) 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 Henry Hub index price used in gas swap and collar contracts.

(g) The average forward basis differential prices are based on October 30, 2015 market quotes for basis differentials between the relevant index prices and NYMEX-quoted forward prices.

(h) 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.

(i) The average forward basis differential prices are based on October 30, 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 September 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 September 30, 2015, these positions had a fair value of nil. Based on October 30, 2015 market quotes, the respective average forward basis differential price was $1.12 per Bbl between the relevant quoted forward oil index prices.

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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 September 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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PIONEER NATURAL RESOURCES COMPANY

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. Except as set forth below, there has been no material change in the Company's risk factors from those described in the Annual Report on Form 10-K.
Climate change regulatory initiatives could result in increased capital expenditures and operating expense.
On October 1, 2015, the U.S. Environmental Protection Agency ("EPA") issued a final rule under the federal Clean Air Act for the purpose of making more stringent the national ambient air quality standards for ground-level ozone. Under its revised rules, the EPA is required to make attainment and non-attainment designations for specific geographic locations considering the newly revised ozone standards by October 1, 2017 and, depending on the severity of the ozone present, non-attainment areas would have until between 2020 and 2037 to meet those new standards. As a result, states may be required to implement more stringent environmental regulations applicable to the affected geographic locations, which could apply to the Company's operations. Compliance with this final rule could increase the Company's capital expenditures and operating expense by, for example, requiring installation of new emission controls on some of the Company's equipment or longer permitting timelines, which could adversely impact the Company's business, financial condition and results of operations. For more information regarding the Company's exposure to costs and liabilities for environmental matters, see "Part I, Item 1A. Risk Factors - The nature of the Company's assets and production operations exposes it to significant costs and liabilities with respect to environmental and occupational health and safety matters" and "- Climate change legislation and regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil, NGLs and gas the Company produces" in the Company's Annual Report on Form 10-K for the year ended December 31, 2014.
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 September 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
July 2015	2,786	$ 137.35	—	
August 2015	4,195	$ 127.22	—	
September 2015	57	$ 118.43	—	
Total	7,038	$ 131.16	—	$—

(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.

Item 6. Exhibits
Exhibits

Exhibit Number		Description
10.1	—	Second Amendment to Second Amended and Restated 5-Year Revolving Credit Agreement dated as of August 31, 2015, among the Company, as the Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and certain other lenders (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on September 4, 2015).
10.2	(a) —	Fifth Amendment to the Pioneer Natural Resources USA, Inc. 401(k) and Matching Plan dated October 29, 2015
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: November 3, 2015	By: /s/ RICHARD P. DEALY Richard P. Dealy, Executive Vice President and Chief Financial Officer
Date: November 3, 2015	By: /s/ MARGARET M. MONTEMAYOR Margaret M. Montemayor, Vice President and Chief Accounting Officer

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