DCP Midstream Partners, LP
Form 10-Q
May 07, 2015
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2015
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-32678

DCP MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	03-0567133 (I.R.S. Employer Identification No.)
370 17th Street, Suite 2500 Denver, Colorado (Address of principal executive offices)	80202 (Zip Code)

Registrant’s telephone number, including area code: (303) 633-2900

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

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

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

Large accelerated filerý	Accelerated filer ¨
Non-accelerated filer ¨	Smaller reporting company¨

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

As of May 1, 2015, there were outstanding 114,738,148 common units representing limited partner interests.

DCP MIDSTREAM PARTNERS, LP
FORM 10-Q FOR THE QUARTER ENDED MARCH 31, 2015
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GLOSSARY OF TERMS

The following is a list of certain industry terms used throughout this report:

Bbl	barrel
Bbls/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Btu	British thermal unit, a measurement of energy
Fractionation	the process by which natural gas liquids are separated into individual components
MBbls	thousand barrels
MBbls/d	thousand barrels per day
MMBtu	million Btus
MMBtu/d	million Btus per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
NGLs	natural gas liquids
Throughput	the volume of product transported or passing through a pipeline or other facility

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Our reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as “may,” “could,” “should,” “intend,” “assume,” “project,” “believe,” “anticipate,” “expect,” “es “potential,” “plan,” “forecast” and other similar words.

All statements that are not statements of historical facts, including, but not limited to, statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in Item 1A. "Risk Factors” in this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2014, including the following risks and uncertainties:

- the extent of changes in commodity prices and the demand for our products and services, our ability to effectively limit a portion of the adverse impact of potential changes in commodity prices through derivative financial instruments, and the potential impact of price and of producers’ access to capital on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;
- the demand for crude oil, residue gas and NGL products;
- the level and success of drilling and quality of production volumes around our assets and our ability to connect supplies to our gathering and processing systems, as well as our residue gas and NGL infrastructure;
- our ability to access the debt and equity markets and the resulting cost of capital, which will depend on general market conditions, our financial and operating results, inflation rates, interest rates, our ability to comply with the covenants in our loan agreements and our debt securities, as well as our ability to maintain our credit ratings;
- our ability to hire, train, and retain qualified personnel and key management to execute our business strategy;
- general economic, market and business conditions;
- volatility in the price of our common units;
- our ability to execute our risk management programs to continue the safe and reliable operation of our assets;
- new, additions to and changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment, including, but not limited to, climate change legislation, regulation of over-the-counter derivatives market and entities, and hydraulic fracturing regulations, or the increased regulation of our industry, and their impact on producers and customers served by our systems;
- our ability to grow through contributions from affiliates, organic growth projects, or acquisitions, and the successful integration and future performance of such assets;
- our ability to purchase propane from our suppliers and make associated profitable sales transactions for our wholesale propane logistics business;
- our ability to construct and start up facilities on budget and in a timely fashion, which is partially dependent on obtaining required construction, environmental and other permits issued by federal, state and municipal governments, or agencies thereof, the availability of specialized contractors and laborers, and the price of and demand for materials;
- the creditworthiness of our customers and the counterparties to our transactions;
- weather, weather-related conditions and other natural phenomena, including, but not limited to, their potential impact on demand for the commodities we sell and the operation of company-owned and third party-owned infrastructure;
- security threats such as military campaigns, terrorist attacks, and cybersecurity breaches, against, or otherwise impacting, our facilities and systems;
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses;
- the amount of gas we gather, compress, treat, process, transport, sell and store, or the NGLs we produce, fractionate, transport and store, may be reduced if the pipelines and storage and fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the gas or NGLs;

- industry changes, including the impact of consolidations, alternative energy sources, technological advances and changes in competition; and
- the amount of collateral we may be required to post from time to time in our transactions.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. The forward-looking statements in this report speak as of the filing date of this report. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2015	December 31, 2014
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$33	$25
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $1 million	73	106
Affiliates	130	164
Inventories	36	63
Unrealized gains on derivative instruments	196	230
Other	2	2
Total current assets	470	590
Property, plant and equipment, net	3,374	3,347
Goodwill	154	154
Intangible assets, net	117	120
Investments in unconsolidated affiliates	1,481	1,459
Unrealized gains on derivative instruments	20	39
Other long-term assets	28	30
Total assets	$5,644	$5,739
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$136	$196
Affiliates	26	27
Current maturities of long-term debt	250	250
Unrealized losses on derivative instruments	33	43
Accrued interest	33	21
Other	47	64
Total current liabilities	525	601
Long-term debt	2,062	2,061
Other long-term liabilities	51	51
Total liabilities	2,638	2,713
Commitments and contingent liabilities		
Equity:		
Limited partners (114,738,148 and 113,949,868 common units issued and outstanding, respectively)	2,964	2,984
General partner	18	18
Accumulated other comprehensive loss	(8)	(9)
Total partners' equity	2,974	2,993
Noncontrolling interests	32	33
Total equity	3,006	3,026
Total liabilities and equity	$5,644	$5,739

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31, 2015	2014
	(Millions, except per unit amounts)	
Operating revenues:		
Sales of natural gas, propane, NGLs and condensate	$189	$371
Sales of natural gas, propane, NGLs and condensate to affiliates	281	642
Transportation, processing and other	56	51
Transportation, processing and other to affiliates	23	32
Gains (losses) from commodity derivative activity, net	5	(3)
Gains (losses) from commodity derivative activity, net — affiliates	14	(12)
Total operating revenues	568	1,081
Operating costs and expenses:		
Purchases of natural gas, propane and NGLs	367	785
Purchases of natural gas, propane and NGLs from affiliates	35	100
Operating and maintenance expense	47	45
Depreciation and amortization expense	29	26
General and administrative expense	3	5
General and administrative expense — affiliates	18	11
Other expense	—	1
Total operating costs and expenses	499	973
Operating income	69	108
Interest expense	(22)	(19)
Earnings from unconsolidated affiliates	23	3
Income before income taxes	70	92
Income tax expense	(1)	(3)
Net income	69	89
Net income attributable to noncontrolling interests	—	(10)
Net income attributable to partners	69	79
Net income attributable to predecessor operations	—	(6)
General partner’s interest in net income	(31)	(26)
Net income allocable to limited partners	$38	$47
Net income per limited partner unit — basic and diluted	$0.33	$0.50
Weighted-average limited partner units outstanding — basic and diluted	114.2	93.4

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended March 31,	
	2015	2014
	(Millions)	
Net income	$69	$89
Other comprehensive income:		
Reclassification of cash flow hedge losses into earnings	1	2
Total other comprehensive income	1	2
Total comprehensive income	70	91
Total comprehensive income attributable to noncontrolling interests	—	(10)
Total comprehensive income attributable to partners	$70	$81

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31,	
	2015	2014
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$69	$89
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	29	26
Earnings from unconsolidated affiliates	(23)	(3)
Distributions from unconsolidated affiliates	26	13
Net unrealized losses on derivative instruments	43	14
Other, net	2	4
Change in operating assets and liabilities, which provided (used) cash, net of effects of acquisitions:		
Accounts receivable	61	(14)
Inventories	27	34
Accounts payable	(59)	(16)
Accrued interest	12	6
Other current assets and liabilities	(3)	(7)
Other long-term assets and liabilities	4	—
Net cash provided by operating activities	188	146
INVESTING ACTIVITIES:		
Capital expenditures	(65)	(63)
Acquisitions, net of cash acquired	—	(100)
Acquisition of unconsolidated affiliates	—	(669)
Investments in unconsolidated affiliates	(25)	(65)
Proceeds from sales of assets	—	1
Net cash used in investing activities	(90)	(896)
FINANCING ACTIVITIES:		
Proceeds from long-term debt	162	719
Payments of long-term debt	(162)	—
Payments of commercial paper, net	—	(314)
Payments of deferred financing costs	—	(6)
Excess purchase price over acquired interests and commodity hedges	—	(14)
Proceeds from issuance of common units, net of offering costs	31	677
Net change in advances to predecessor from DCP Midstream, LLC	—	(6)
Distributions to limited partners and general partner	(120)	(86)
Distributions to noncontrolling interests	(1)	(10)
Purchase of additional interest in a subsidiary	—	(198)
Contributions from noncontrolling interests	—	3
Net cash (used in) provided by financing activities	(90)	765
Net change in cash and cash equivalents	8	15
Cash and cash equivalents, beginning of period	25	12
Cash and cash equivalents, end of period	$33	$27

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

	Partners' Equity				
	Limited Partners	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
	(Millions)				
Balance, January 1, 2015	$2,984	$18	$(9)	$33	$3,026
Net income	38	31	—	—	69
Other comprehensive income	—	—	1	—	1
Issuance of 788,033 common units to the public	31	—	—	—	31
Distributions to limited partners and general partner	(89)	(31)	—	—	(120)
Distributions to noncontrolling interests	—	—	—	(1)	(1)
Balance, March 31, 2015	$2,964	$18	$(8)	$32	$3,006

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

	Partners' Equity					
	Predecessor Equity	Limited Partners	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
	(Millions)					
Balance, January 1, 2014	$40	$1,948	$8	$ (11)	$ 228	$2,213
Net income	6	47	26	—	10	89
Other comprehensive income	—	—	—	2	—	2
Net change in parent advances	(6)	—	—	—	—	(6)
Acquisition of Lucerne 1 plant	(40)	—	—	—	—	(40)
Issuance of 4,497,158 units to DCP Midstream, LLC and affiliates	—	225	—	—	—	225
Excess purchase price over carrying value of interests acquired in March 2014 Transactions	—	(158)	—	—	—	(158)
Issuance of 14,375,000 common units to the public	—	677	—	—	—	677
Distributions to limited partners and general partner	—	(65)	(21)	—	—	(86)
Distributions to noncontrolling interests	—	—	—	—	(10)	(10)
Contributions from noncontrolling interests	—	—	—	—	3	3
Purchase of additional interest in a subsidiary	—	—	—	—	(198)	(198)
Balance, March 31, 2014	$—	$2,674	$13	$ (9)	$ 33	$2,711

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three Months Ended March 31, 2015 and 2014
(Unaudited)

1. Description of Business and Basis of Presentation

DCP Midstream Partners, LP, with its consolidated subsidiaries, or us, we, our or the Partnership, is engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; producing, fractionating, transporting, storing and selling NGLs and recovering and selling condensate; and transporting, storing and selling propane in wholesale markets.

We are a Delaware limited partnership that was formed in August 2005. Our partnership includes our Natural Gas Services, NGL Logistics and Wholesale Propane Logistics segments. For additional information regarding these segments, see Note 14 - Business Segments.

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as the General Partner, and is 100% owned by DCP Midstream, LLC. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, is owned 50% by Phillips 66 and 50% by Spectra Energy Corp and its affiliates, or Spectra Energy. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. DCP Midstream, LLC’s employees provide administrative support to us and operate most of our assets. DCP Midstream, LLC owns approximately 21.4% of us, including limited partner and general partner interests.

The condensed consolidated financial statements include the accounts of the Partnership and all majority-owned subsidiaries where we have the ability to exercise control. Investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, are accounted for using the equity method.

Our predecessor results consist of the Lucerne 1 plant, which we acquired from DCP Midstream, LLC on March 28, 2014. This transfer of net assets between entities under common control was accounted for as if the transfer occurred at the beginning of the period, and prior periods were retrospectively adjusted to furnish comparative information, similar to the pooling method. Accordingly, our condensed consolidated financial statements include the historical results of our Lucerne 1 plant for all periods presented.

The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the condensed consolidated financial statements and notes. Although these estimates are based on management’s best available knowledge of current and expected future events, actual results could differ from those estimates. All intercompany balances and transactions have been eliminated. Transactions between us and other DCP Midstream, LLC operations have been included in the condensed consolidated financial statements as transactions between affiliates.

The accompanying unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission, or SEC. Accordingly, these condensed consolidated financial statements reflect all adjustments, consisting of normal recurring adjustments, that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective interim periods. Certain information and note disclosures normally included in our annual financial statements prepared in accordance with GAAP have been condensed or omitted from these interim financial statements pursuant to such rules and regulations, although we believe that the disclosures made are adequate to make the information not misleading. Results of operations for the three months ended March 31, 2015 are not necessarily indicative of the results that may be expected for the year ending December 31, 2015. These unaudited condensed consolidated financial statements and other information included in this Quarterly Report on Form 10-Q should be read in conjunction with the 2014 audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2014.

2. New Accounting Pronouncements

Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2015-06 “Earnings Per Share (Topic 260): Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions,” or ASU 2015-06 - In April 2015, the FASB issued ASU 2015-06, which specifies that for purposes of calculating historical earnings per unit under the two-class method, the earnings or losses of a transferred business before the date of a dropdown transaction should be allocated entirely to the general partner. In that circumstance, the previously reported earnings per unit of the limited partners, which is typically the earnings per unit measure presented in the financial statements, would not change as a result of the dropdown transaction. This ASU is effective for annual and interim reporting periods beginning after December 15, 2015 and is required to be applied retrospectively. The adoption of this ASU will have no impact on our condensed consolidated results of operations as we have not historically changed previously reported earnings per limited partner unit as a result of dropdown transactions.

FASB ASU 2015-03 “Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Cost,” or ASU 2015-03 - In April 2015, the FASB issued ASU 2015-03, which requires debt issuance costs to be presented in the balance sheet as a direct deduction from the associated debt liability. This ASU is effective for annual reporting periods beginning after December 15, 2015, after which we will present debt issuance costs as a direct reduction from debt on our condensed consolidated balance sheets for all periods presented. The adoption of this ASU will have no impact on our condensed consolidated results of operations and cash flows.

FASB ASU 2015-02 “Consolidation (Topic 810): Amendments to the Consolidation Analysis,” or ASU 2015-02 - In February 2015, the FASB issued ASU 2015-02, which changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. This ASU is effective for annual reporting periods beginning after December 15, 2015 and we are currently assessing the impact of adoption of this ASU on our condensed consolidated results of operations, cash flows and financial position.

FASB ASU 2014-09 “Revenue from Contracts with Customers (Topic 606),” or ASU 2014-09 - In May 2014, the FASB issued ASU 2014-09, which supersedes the revenue recognition requirements of Accounting Standards Codification, or ASC, Topic 605 “Revenue Recognition.” This ASU is effective for annual reporting periods beginning after December 15, 2016. In April 2015, the FASB proposed to defer the effective date of the ASU to December 15, 2017, with the option to adopt as early as December 15, 2016. The FASB has not yet voted on the proposal. We are currently assessing the impact of adoption of this ASU on our condensed consolidated results of operations, cash flows and financial position.

3. Acquisitions

On January 1, 2015, we entered into an agreement with an affiliate of Enterprise Products Partners L.P., or Enterprise, to acquire a 15% ownership interest in Panola Pipeline Company, LLC, or Panola. At closing, we paid $1 million for our interest in the joint venture. The anticipated total consideration of approximately $26 million includes our proportionate share in construction costs for an anticipated expansion of the existing Panola NGL pipeline. The Panola NGL pipeline originates in Carthage, Texas and extends approximately 180 miles to Mont Belvieu, Texas. The expansion will extend the Panola NGL pipeline approximately 60 miles and increase capacity from approximately 50 MBbls/d to 100 MBbls/d. We, WGR Asset Holding Company LLC, which is an affiliate of Anadarko Petroleum Corporation, and MarkWest Panola Pipeline L.L.C. will each own a 15% interest in Panola. Enterprise will own a 55% interest in Panola and will construct the expansion and operate the pipeline. In accordance with the joint venture agreement, we will not participate in the earnings of the Panola pipeline until the expansion is complete, which is expected to be in service in the first quarter of 2016.

4. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Services Agreement and Other General and Administrative Charges

We have entered into a services agreement, as amended, or the Services Agreement, with DCP Midstream, LLC. Under the Services Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits, as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee under the Services Agreement for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering. Except with respect to the annual fee, there is no limit on the reimbursements we make to DCP Midstream, LLC under the Services Agreement for other expenses and expenditures incurred or payments made on our behalf. In the event we acquire assets or our business otherwise expands, the annual fee under the Services Agreement is subject to adjustment based on the nature and extent of general and administrative services performed by DCP Midstream, LLC, as well as an annual adjustment based on changes to the Consumer Price Index.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three Months Ended March 31, 2015 and 2014 - (Continued)
(Unaudited)

On February 23, 2015, the annual fee payable under the Services Agreement was increased by approximately $25 million to $71 million, following approval of the increase by the special committee of the board of directors of the General Partner. Our growth, both from organic growth and acquisitions, has resulted in the Partnership becoming a much larger portion of the business of DCP Midstream, LLC. Additionally, our expansion into downstream logistics has required DCP Midstream, LLC to expand its capabilities and provide us with a broader range of services than what was previously provided. As a result, DCP Midstream, LLC initiated a comprehensive review of its costs and the methodology for allocating general and administrative services. The result of this review reflects the level and cost of general and administrative services provided to us by DCP Midstream, LLC as the operator of our assets. The annual fee was effective starting January 1, 2015.

The following is a summary of the fees we incurred under the Services Agreement, as well as other fees paid to DCP Midstream, LLC:

	Three Months Ended March 31,	
	2015	2014
	(Millions)	
Services Agreement	$18	$7
Other fees — DCP Midstream, LLC	—	4
Total — DCP Midstream, LLC	$18	$11

In addition to the fees paid pursuant to the Services Agreement, we incurred allocated expenses, including executive compensation, insurance and internal audit fees with DCP Midstream, LLC of less than $1 million for each of the three months ended March 31, 2015 and 2014. The Eagle Ford system incurred $4 million in general and administrative expenses directly from DCP Midstream, LLC for the three months ended March 31, 2014, before the reallocation of the Eagle Ford system to the Services Agreement on March 31, 2014.

Other Agreements and Transactions with DCP Midstream, LLC

As a result of assets contributed to us by DCP Midstream, LLC, we have previously entered into derivative transactions directly with DCP Midstream, LLC whereby DCP Midstream, LLC was the counterparty. In March 2015, DCP Midstream, LLC novated those fixed price derivatives and our counterparty is now one of the financial institutions associated with our credit facility. Accordingly, the counterparties to the majority of our commodity swap contracts are investment-grade rated financial institutions.

In conjunction with our acquisition of the O'Connor and Lucerne 1 plants, we entered into long-term fee-based processing agreements with DCP Midstream, LLC pursuant to which DCP Midstream, LLC agreed to pay us (i) a fixed demand charge on a portion of the plants' capacities, and (ii) a throughput fee on all volumes processed for DCP Midstream, LLC at the plants. We report revenues associated with these activities in the condensed consolidated statements of operations as transportation, processing and other to affiliates. Under the O'Connor agreement, we received fees of $9 million and $7 million during the three months ended March 31, 2015 and 2014. Under the Lucerne 1 agreement, we received fees of $3 million during the three months ended March 31, 2015.

Spectra Energy

Commodity Transactions - We purchase natural gas and other NGL products from and provide gathering, transportation and other services to Spectra Energy. Management anticipates continuing to purchase and sell commodities and provide services to Spectra Energy in the ordinary course of business.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three Months Ended March 31, 2015 and 2014 - (Continued)
(Unaudited)

Summary of Transactions with Affiliates
The following table summarizes our transactions with affiliates:

	Three Months Ended March 31,	
	2015	2014
	(Millions)	
DCP Midstream, LLC:		
Sales of natural gas, propane, NGLs and condensate	$281	$642
Transportation, processing and other	$23	$18
Purchases of natural gas, propane and NGLs	$25	$80
Gains from commodity derivative activity, net	$14	$(12)
General and administrative expense	$18	$11
Spectra Energy:		
Purchases of natural gas, propane and NGLs	$10	$20
Transportation, processing and other	$—	$14

We had balances with affiliates as follows:

	March 31, 2015	December 31, 2014
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$130	$163
Accounts payable	$21	$24
Unrealized gains on derivative instruments — current	$32	$207
Unrealized gains on derivative instruments — long-term	$7	$25
Unrealized losses on derivative instruments — current	$33	$43
Spectra Energy:		
Accounts receivable	$—	$1
Accounts payable	$5	$3

5. Inventories
Inventories were as follows:

	March 31, 2015	December 31, 2014
	(Millions)	
Natural gas	$21	$36
NGLs	15	27
Total inventories	$36	$63

We recognize lower of cost or market adjustments when the carrying value of our inventories exceeds their estimated market value. These non-cash charges are a component of purchases of natural gas, propane and NGLs in the condensed consolidated statements of operations. We recognized $4 million and $3 million in lower of cost or market adjustments during the three months ended March 31, 2015 and 2014, respectively.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three Months Ended March 31, 2015 and 2014 - (Continued)
(Unaudited)

6. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows:

	Depreciable Life	March 31, 2015	December 31, 2014
		(Millions)	
Gathering and transmission systems	20 — 50 Years	$2,267	$2,209
Processing, storage, and terminal facilities	35 — 60 Years	2,042	2,071
Other	3 — 30 Years	55	50
Construction work in progress		300	281
Property, plant and equipment		4,664	4,611
Accumulated depreciation		(1,290)	(1,264)
Property, plant and equipment, net		$3,374	$3,347

Interest capitalized on construction projects for the three months ended March 31, 2015 and 2014 was $3 million and $1 million, respectively.

Depreciation expense was $26 million and $24 million for the three months ended March 31, 2015 and 2014, respectively.

7. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage Ownership	Carrying Value as of March 31, 2015	December 31, 2014
		(Millions)	
DCP Sand Hills Pipeline, LLC	33.33%	$427	$413
Discovery Producer Services LLC	40%	413	406
DCP Southern Hills Pipeline, LLC	33.33%	327	329
Front Range Pipeline LLC	33.33%	171	169
Texas Express Pipeline LLC	10%	98	98
Mont Belvieu Enterprise Fractionator	12.5%	24	23
Mont Belvieu 1 Fractionator	20%	13	14
Other	Various	8	7
Total investments in unconsolidated affiliates		$1,481	$1,459

Earnings (losses) from investments in unconsolidated affiliates were as follows:

	Three Months Ended March 31, 2015	2014
	(Millions)	
DCP Sand Hills Pipeline, LLC	$11	$—
Mont Belvieu Enterprise Fractionator	4	4
Front Range Pipeline LLC	4	(1)
DCP Southern Hills Pipeline, LLC	3	—
Texas Express Pipeline LLC	2	—
Mont Belvieu 1 Fractionator	1	1
Discovery Producer Services LLC	(2)	(1)
Total earnings from unconsolidated affiliates	$23	$3

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The following tables summarize the combined financial information of our investments in unconsolidated affiliates:

	Three Months Ended March 31,	
	2015	2014
	(Millions)	
Statements of operations (a):		
Operating revenue	$233	$111
Operating expenses	$129	$82
Net income	$103	$29

	March 31, 2015	December 31, 2014
	(Millions)	
Balance sheets (a):		
Current assets	$200	$207
Long-term assets	5,270	5,157
Current liabilities	(195)	(200)
Long-term liabilities	(239)	(164)
Net assets	$5,036	$5,000

(a) In accordance with the Panola joint venture agreement, earnings do not accrue to our interest until the expansion of the pipeline is complete. Accordingly, we will not include activity related to Panola in the above tables until the period in which the expansion is complete and earnings accrue to our interest.

8. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities which are measured at fair value. Fair values are generally based upon quoted market prices or prices obtained through external sources, where available. If listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an “exit price” methodology, in line with how we believe a marketplace participant would value that asset or liability. Fair values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money and/or the liquidity of the market.

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us as well as any letters of credit that they have provided.
- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability positions with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement

date.

- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets and liabilities. Although we take a portfolio approach to managing these assets/liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level, to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 10 - Risk Management and Hedging Activities.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.

- Level 1 — inputs are unadjusted quoted prices for identical assets or liabilities in active markets.
- Level 2 — inputs include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

A financial instrument's categorization within the hierarchy is based upon the level of judgment involved in the most significant input in the determination of the instrument's fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include over the counter, or OTC, instruments, such as natural gas, crude oil or NGL contracts.

Within our Natural Gas Services segment, we typically use OTC derivative contracts in order to mitigate a portion of our exposure to natural gas, NGL and condensate price changes. We also may enter into natural gas derivatives to lock in margin around our storage and transportation assets. These instruments are generally classified as Level 2. Depending upon market conditions and our strategy, we may enter into OTC derivative positions with a significant time horizon to maturity, and market prices for these OTC derivatives may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent that it is available; however, in the event that readily observable market data is not available, we may interpolate or extrapolate based upon observable data. In instances where we utilize an interpolated or extrapolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

Within our Wholesale Propane Logistics segment, we may enter into a variety of financial instruments to either secure sales or purchase prices, or capture a variety of market opportunities. Since financial instruments for NGLs tend to be counterparty and location specific, we primarily use the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and an active market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, data obtained from third party pricing services, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.
Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

Interest Rate Derivative Assets and Liabilities

We may use interest rate swap agreements as part of our overall capital strategy. These instruments would effectively exchange a portion of our existing floating rate debt for fixed-rate debt. Historically, our swaps have been generally priced based upon a London Interbank Offered Rate, or LIBOR, instrument with similar duration, adjusted by the credit spread between our company and the LIBOR instrument. Given that a portion of the swap value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified within Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit and entity valuation adjustments in the valuation of our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Nonfinancial Assets and Liabilities

We utilize fair value to perform impairment tests as required on our property, plant and equipment; goodwill; and long-lived intangible assets. Assets and liabilities acquired in third party business combinations are recorded at their fair value as of the date of acquisition. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified within Level 3 in the event that we were required to measure and record such assets at fair value within our condensed consolidated financial statements. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified within Level 3.

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The following table presents the financial instruments carried at fair value as of March 31, 2015 and December 31, 2014, by condensed consolidated balance sheet caption and by valuation hierarchy, as described above:

	March 31, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets:								
Commodity derivatives (a)	$—	$78	$118	$196	$—	$92	$138	$230
Short-term investments (b)	$33	$—	$—	$33	$24	$—	$—	$24
Long-term assets (c):								
Commodity derivatives	$—	$20	$—	$20	$—	$21	$18	$39
Current liabilities (d):								
Commodity derivatives	$—	$(33)	$—	$(33)	$—	$(43)	$—	$(43)

(a) Included in current unrealized gains on derivative instruments in our condensed consolidated balance sheets.
(b) Includes short-term money market securities included in cash and cash equivalents in our condensed consolidated balance sheets.
(c) Included in long-term unrealized gains on derivative instruments in our condensed consolidated balance sheets.
(d) Included in current unrealized losses on derivative instruments in our condensed consolidated balance sheets.

Changes in Levels 1 and 2 Fair Value Measurements

The determination to classify a financial instrument within Level 1 or Level 2 is based upon the availability of quoted prices for identical or similar assets and liabilities in active markets. Depending upon the information readily observable in the market, and/or the use of identical or similar quoted prices, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. To qualify as a transfer, the asset or liability must have existed in the previous reporting period and moved into a different level during the current period. In the event that there is a movement between the classification of an instrument as Level 1 or 2, the transfer would be reflected in a table as Transfers into or out of Level 1 and Level 2. During the three months ended March 31, 2015 and 2014, there were no transfers into or out of Level 1 and Level 2 of the fair value hierarchy.

Changes in Level 3 Fair Value Measurements

The tables below illustrate a rollforward of the amounts included in our condensed consolidated balance sheets for derivative financial instruments that we have classified within Level 3. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. The significant unobservable inputs used in determining fair value include adjustments by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. In the event that there is a movement to/from the classification of an instrument as Level 3, we would reflect such items in the table below within the “Transfers into/out of Level 3” captions.

We manage our overall risk at the portfolio level and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforward below, the gains or losses in the table do not reflect the effect of our total risk management activities.

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	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Three months ended March 31, 2015 (a):				
Beginning balance	$138	$18	$—	$—
Net unrealized gains (losses) included in earnings (b)	20	(18)	—	—
Settlements	(40)	—	—	—
Ending balance	$118	$—	$—	$—
Net unrealized gains (losses) on derivatives still held included in earnings (b)	$20	$(18)	$—	$—
Three months ended March 31, 2014 (a):				
Beginning balance	$65	$75	$—	$—
Net unrealized gains (losses) included in earnings (b)	17	(15)	(1)	—
Settlements	(12)	—	—	—
Ending balance	$70	$60	$(1)	$—
Net unrealized gains (losses) on derivatives still held included in earnings (b)	$19	$(15)	$(1)	$—

(a) There were no purchases, issuances or sales of derivatives or transfers into/out of Level 3 for the three months ended March 31, 2015 and 2014.

(b) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net.

Quantitative Information and Fair Value Sensitivities Related to Level 3 Unobservable Inputs

We utilize the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach to fair value are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending on our short or long position in contracts.

	March 31, 2015		
Product Group	Fair Value	Forward Curve Range	
	(Millions)		
Assets			
NGLs	$118	$0.17-$1.12	Per gallon

Estimated Fair Value of Financial Instruments

Valuation of a contract's fair value is validated by an internal group independent of the marketing group. While common industry practices are used to develop valuation techniques, changes in pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected relationship with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

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The fair value of our interest rate swaps, if any, and commodity non-trading derivatives is based on prices supported by quoted market prices and other external sources and prices based on models and other valuation methods. The “prices supported by quoted market prices and other external sources” category includes our interest rate swaps, if any, our NGL and crude oil swaps and our NYMEX positions in natural gas. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third party pricing service and then validated through an internal process which includes the use of independent broker quotes. This category also includes our forward positions in NGLs at points for which OTC broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes “strip” transactions whose pricing inputs are directly or indirectly observable from external sources and then modeled to daily or monthly prices as appropriate. The “prices based on models and other valuation methods” category includes the value of transactions for which inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which was constructed as a result of the long dated nature of the transaction or the illiquidity of the specific market point.

We have determined fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

The fair value of accounts receivable, accounts payable and short-term borrowings are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Derivative instruments are carried at fair value.

We determine the fair value of our fixed-rate Senior Notes based on quotes obtained from bond dealers. We classify the fair values of our outstanding debt balances within Level 2 of the valuation hierarchy. As of March 31, 2015 and December 31, 2014, the carrying value and fair value of our long-term fixed-rate Senior Notes, including current maturities, were as follows:

	March 31, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(Millions)			
Senior Notes	$2,312	$2,157	$2,311	$2,334

9. Debt

	March 31, 2015	December 31, 2014
	(Millions)	
Debt Securities		
Issued September 30, 2010, interest at 3.25% payable semi-annually, due October 1, 2015	250	250
Issued November 27, 2012, interest at 2.50% payable semi-annually, due December 1, 2017	500	500
Issued March 13, 2014, interest at 2.70% payable semi-annually, due April 1, 2019	325	325
Issued March 13, 2012, interest at 4.95% payable semi-annually, due April 1, 2022	350	350
	500	500

Issued March 14, 2013, interest at 3.875% payable semi-annually, due March 15, 2023		
Issued March 13, 2014, interest at 5.60% payable semi-annually, due April 1, 2044	400	400
Unamortized discount	(13)	(14)
Total debt	2,312	2,311
Current maturities of long-term debt	(250)	(250)
Total long-term debt	$2,062	$2,061

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Amended and Restated Credit Agreement

On May 1, 2014, we entered into a $1.25 billion amended and restated senior unsecured revolving credit agreement that matures on May 1, 2019, or the Amended and Restated Credit Agreement. The Amended and Restated Credit Agreement will be used for working capital requirements and other general partnership purposes including acquisitions.

Our cost of borrowing under the Amended and Restated Credit Agreement is determined by a ratings-based pricing grid. In the first quarter of 2015, our credit rating was lowered below investment grade. As a result of this ratings action, interest rates under the Amended and Restated Credit Agreement increased to: (1) LIBOR, plus an applicable margin of 1.45% based on our current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A.'s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1%, plus (b) an applicable margin of 0.45% based on our current credit rating. The Amended and Restated Credit Agreement incurs an annual facility fee of 0.30% based on our current credit rating. This fee is paid on drawn and undrawn portions of the $1.25 billion Amended and Restated Credit Agreement.

As of March 31, 2015, we had unused capacity of $1,249 million, net of letters of credit, under the Amended and Restated Credit Agreement, of which $1,205 million was available for general working capital purposes. Our borrowing capacity may be limited by financial covenant requirements set forth in the Amended and Restated Credit Agreement. Except in the case of a default, amounts borrowed under our Amended and Restated Credit Agreement will not become due prior to the May 1, 2019 maturity date.

The Amended and Restated Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Credit Agreement) of not more than 5.0 to 1.0, and following the consummation of qualifying acquisitions, not more than 5.5 to 1.0, on a temporary basis for three consecutive quarters, including the quarter in which such acquisition is consummated.

Commercial Paper Program

Prior to March 2015, we had a commercial paper program, or the Commercial Paper Program, under which we issued unsecured commercial paper notes. During the first quarter of 2015, our credit rating was lowered below investment grade. As a result of this ratings action, we no longer have the Commercial Paper Program. Our available liquidity under the Commercial Paper Program was replaced with the Amended and Restated Credit Agreement.

Debt Securities

In March 2014, we issued $325 million of 2.70% five-year Senior Notes due April 1, 2019 and $400 million of 5.60% 30-year Senior Notes due April 1, 2044. We received proceeds of $320 million and $392 million, respectively, net of underwriters' fees, related expenses and unamortized discounts which we used to pay a portion of the consideration for the contribution and acquisition of: (i) a 33.33% interest in each of the Sand Hills and Southern Hills pipeline entities; (ii) the remaining 20% interest in the Eagle Ford system; (iii) the Lucerne 1 plant; and (iv) the Lucerne 2 plant, or the March 2014 Transactions. Interest on the notes is paid semi-annually on April 1 and October 1 of each year, commencing October 1, 2014. The notes will mature on April 1, 2019 and April 1, 2044, respectively, unless redeemed prior to maturity.

The notes are senior unsecured obligations, ranking equally in right of payment with other unsecured indebtedness, including indebtedness under our Amended and Restated Credit Agreement. We are not required to make mandatory redemption or sinking fund payments with respect to any of these notes, and they are redeemable at a premium at our option. The underwriters' fees and related expenses are deferred in other long-term assets in our condensed consolidated balance sheets and will be amortized over the term of the notes.

The future maturities of long-term debt in the year indicated are as follows:

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	Debt Maturities (Millions)
2016	$—
2017	500
2018	—
2019	325
2020	—
Thereafter	1,250
	2,075
Unamortized discount	(13)
Total	$2,062

10. Risk Management and Hedging Activities

Our day-to-day operations expose us to a variety of risks including but not limited to changes in the prices of commodities that we buy or sell, changes in interest rates, and the creditworthiness of each of our counterparties. We manage certain of these exposures with either physical or financial transactions. We have established a comprehensive risk management policy and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices and counterparty credit. The Risk Management Committee is composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The following describes each of the risks that we manage.

Commodity Price Risk

Cash Flow Protection Activities — We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, sales and storage activities. For gathering, processing and storage services, we may receive cash or commodities as payment for these services, depending on the contract type. We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. We have mitigated a portion of our expected commodity price risk associated with our gathering, processing and sales activities through 2017 with commodity derivative instruments, with the majority of our positions settling through the first quarter of 2016. Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, we have used crude oil swaps and costless collars to mitigate a portion of our commodity price exposure to NGLs. Historically, prices of NGLs have generally been related to crude oil prices; however, there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. The relationship of NGLs to crude oil continues to be lower than historical relationships; however, a significant amount of our NGL hedges from 2015 through 2016 are direct product hedges. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. Our crude oil and NGL transactions are primarily accomplished through the use of forward contracts that effectively exchange our floating price risk for a fixed price. We also utilize crude oil costless collars that minimize our floating price risk by establishing a fixed price floor and a fixed price ceiling. However, the type of instrument that we use to mitigate a portion of our risk may vary depending upon our risk management objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected within our condensed consolidated statements of operations as a gain or a loss on commodity derivative activity.

Our Wholesale Propane Logistics segment is generally designed with the intent to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. However, to the extent that we carry propane inventories or our sales and supply arrangements are not aligned, we are exposed to market variables and commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions, including fixed price sales. While the majority of our sales and purchases in this segment are index-based, occasionally, we may enter into fixed price sales agreements in the event that a propane distributor

desires to purchase propane from us on a fixed price basis. In such cases, we may manage this risk with derivatives that allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may use financial derivatives to manage the value of our propane inventories. These transactions are not designated as hedging instruments for accounting purposes and any change in fair value is reflected in the current period within our condensed consolidated statements of operations as a gain or loss on commodity derivative activity.
Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting, whereby changes in fair value are recorded directly to the condensed consolidated statements of operations; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting.
As a result of assets contributed to us by DCP Midstream, LLC, we have previously entered into derivative transactions directly with DCP Midstream, LLC whereby DCP Midstream, LLC was the counterparty. In March 2015, DCP Midstream, LLC novated those fixed price derivatives and our counterparty is now one of the financial institutions associated with our credit facility. Accordingly, the counterparties to the majority of our commodity swap contracts are investment-grade rated financial institutions.
Natural Gas Storage and Pipeline Asset Based Commodity Derivative Program — Our natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.
A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period condensed consolidated statements of operations.
While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our condensed consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.
Commodity Cash Flow Hedges — In order for storage facilities to remain operational, a minimum level of base gas must be maintained in each storage cavern, which is capitalized on our condensed consolidated balance sheets as a component of property, plant and equipment, net. During construction or expansion of our storage caverns, we may execute a series of derivative financial instruments to mitigate a portion of the risk associated with the forecasted purchase of natural gas when we bring the storage caverns to operation. These derivative financial instruments may be designated as cash flow hedges. While the cash paid upon settlement of these hedges economically fixes the cash required to purchase the base gas, the deferred losses or gains would remain in accumulated other comprehensive income, or AOCI, until the cavern is emptied and the base gas is sold. The balance in AOCI of our previously settled base gas cash flow hedges was in a loss position of $6 million as of March 31, 2015.

Interest Rate Risk

We enter into debt arrangements that have either fixed or floating rates, therefore we are exposed to market risks related to changes in interest rates. We periodically use interest rate swaps to convert our floating rate debt to fixed-rate debt or to convert our fixed-rate debt to floating rate debt. Our primary goals include: (1) maintaining an appropriate ratio of fixed-rate debt to floating-rate debt; (2) reducing volatility of earnings resulting from interest rate fluctuations; and (3) locking in attractive interest rates.

Prior to June 30, 2014, we had interest rate swap agreements with notional values totaling $150 million, which were accounted for under the mark-to-market method of accounting and repriced prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, we paid fixed-rates ranging from 2.94% to 2.99%, and received interest payments based on the one-month LIBOR. These interest rate swap agreements settled in June 2014. Prior to August of 2013, these interest rate swaps were designated as cash flow hedges whereby the effective portions of changes in fair value were recognized in AOCI in the condensed consolidated balance sheets. In March 2014, we paid down a portion of the balance outstanding under our Commercial Paper Program and reclassified the remaining loss of $1 million in AOCI into earnings as interest expense.

In conjunction with the issuance of our 4.95% Senior Notes in March 2012, we entered into forward-starting interest rate swap agreements to reduce our exposure to market rate fluctuations prior to issuance. These derivative financial instruments were designated as cash flow hedges. While the cash paid upon settlement of these hedges economically fixed the rate we would pay on a portion of our 4.95% Senior Notes, the deferred loss in AOCI will be amortized into interest expense through the maturity of the notes in 2022. The balance in AOCI of these cash flow hedges was in a loss position of $3 million as of March 31, 2015.

Contingent Credit Features

Each of the above risks is managed through the execution of individual contracts with a variety of counterparties. Certain of our derivative contracts may contain credit-risk related contingent provisions that may require us to take certain actions in certain circumstances.

We have International Swaps and Derivatives Association, or ISDA, contracts which are standardized master legal arrangements that establish key terms and conditions which govern certain derivative transactions. These ISDA contracts contain standard credit-risk related contingent provisions. Some of the provisions we are subject to are outlined below.

- If we were to have an effective event of default under our Amended and Restated Credit Agreement that occurs and is continuing, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions.
- Certain of our ISDA counterparties would have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position, when our credit rating is below investment grade.
- Additionally, in some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. These provisions apply if we default in making timely payments under other credit arrangements and the amount of the default is above certain predefined thresholds, which are significantly high and are generally consistent with the terms of our Amended and Restated Credit Agreement. As of March 31, 2015, we were not a party to any agreements that would trigger the cross-default provisions.

Our commodity derivative contracts that are not governed by ISDA contracts do not have any credit-risk related contingent features.

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or to our interest rate swap instruments are in either a net asset or net liability position. As of March 31, 2015, all of our individual commodity derivative contracts that contain credit-risk related contingent features were in a net asset position. If we were required to net settle our position with an individual counterparty, due to a credit-risk related event, our ISDA contracts may permit us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of March 31, 2015, we were not required to post additional collateral or offset net liability contracts with contracts in a net asset position because all of our commodity derivative contracts that contain credit-risk related contingent features were in a net asset position.

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Offsetting
Certain of our derivative instruments are subject to a master netting or similar arrangement, whereby we may elect to settle multiple positions with an individual counterparty through a single net payment. Each of our individual derivative instruments are presented on a gross basis on the condensed consolidated balance sheets, regardless of our ability to net settle our positions. Instruments that are governed by agreements that include net settle provisions allow final settlement, when presented with a termination event, of outstanding amounts by extinguishing the mutual debts owed between the parties in exchange for a net amount due. We have trade receivables and payables associated with derivative instruments, subject to master netting or similar agreements, which are not included in the table below. The following summarizes the gross and net amounts of our derivative instruments:

	March 31, 2015			December 31, 2014		
	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments (a)	Net Amount	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments (a)	Net Amount
	(Millions)					
Assets:						
Commodity derivatives	$216	$ (32)	$184	$269	$ (42)	$227
Liabilities:						
Commodity derivatives	$(33)	$ 32	$(1)	$(43)	$ 42	$(1)

(a) There is no cash collateral pledged or received against these positions.

Summarized Derivative Information
The fair value of our derivative instruments that are marked-to-market each period, as well as the location of each within our condensed consolidated balance sheets, by major category, is summarized below. We have no derivative instruments that are designated as hedging instruments for accounting purposes as of March 31, 2015 and December 31, 2014.

Balance Sheet Line Item	March 31, 2015	December 31, 2014	Balance Sheet Line Item	March 31, 2015	December 31, 2014
	(Millions)			(Millions)	
Derivative Assets Not Designated as Hedging Instruments:			Derivative Liabilities Not Designated as Hedging Instruments:		
Commodity derivatives:			Commodity derivatives:		
Unrealized gains on derivative instruments — current	$196	$230	Unrealized losses on derivative instruments — current	$(33)	$(43)
Unrealized gains on derivative instruments — long-term	20	39	Unrealized losses on derivative instruments — long-term	—	—
	$216	$269		$(33)	$(43)

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The following summarizes the balance and activity within AOCI relative to our interest rate, commodity and foreign currency cash flow hedges as of and for the three months ended March 31, 2015:

	Interest Rate Cash Flow Hedges (Millions)	Commodity Cash Flow Hedges	Foreign Currency Cash Flow Hedges (a)	Total
Net deferred (losses) gains in AOCI (beginning balance)	$(4)	$(6)	$1	$(9)
Losses reclassified from AOCI to earnings — effective portion	1 (b)	—	—	1
Net deferred (losses) gains in AOCI (ending balance)	$(3)	$(6)	$1	$(8)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$(1)	$—	$—	$(1)

(a) Relates to Discovery, our unconsolidated affiliate.
(b) Included in interest expense in our condensed consolidated statements of operations.

For the three months ended March 31, 2015, no derivative losses attributable to the ineffective portion or to amounts excluded from effectiveness testing were recognized in gains or losses from commodity derivative activity, net or interest expense in our condensed consolidated statements of operations. For the three months ended March 31, 2015, no derivative losses were reclassified from AOCI to gains or losses from commodity derivative activity, net or interest expense as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

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The following summarizes the balance and activity within AOCI relative to our interest rate, commodity and foreign currency cash flow hedges as of and for the three months ended March 31, 2014:

	Interest Rate Cash Flow Hedges	Commodity Cash Flow Hedges	Foreign Currency Cash Flow Hedges (a)	Total
	(Millions)			
Net deferred (losses) gains in AOCI (beginning balance)	$(6)	$(6)	$1	$(11)
Losses reclassified from AOCI to earnings — effective portion	$2 (b)	$—	$—	$2
Net deferred (losses) gains in AOCI (ending balance)	$(4)	$(6)	$1	$(9)

(a) Relates to Discovery, our unconsolidated affiliate.
(b) Included in interest expense in our condensed consolidated statements of operations.

For the three months ended March 31, 2014, no derivative losses attributable to the ineffective portion or to amounts excluded from effectiveness testing were recognized in gains or losses from commodity derivative activity, net or interest expense in our condensed consolidated statements of operations. For the three months ended March 31, 2014, $1 million of derivative losses were reclassified from AOCI to interest expense as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

Changes in value of derivative instruments, for which the hedge method of accounting has not been elected from one period to the next, are recorded in the condensed consolidated statements of operations. The following summarizes these amounts and the location within the condensed consolidated statements of operations that such amounts are reflected:

Commodity Derivatives: Statements of Operations Line Item	Three Months Ended March 31, 2015	2014
	(Millions)	
Third party:		
Realized gains (losses)	$7	$(3)
Unrealized losses	(2)	—
Gains (losses) from commodity derivative activity, net	$5	$(3)
Affiliates:		
Realized gains	$54	$1
Unrealized losses	(40)	(13)
Gains (losses) from commodity derivative activity, net —affiliates	$14	$(12)

Interest Rate Derivatives: Statements of Operations Line Item	Three Months Ended March 31, 2015	2014
	(Millions)	
Third party:		
Realized losses	$—	$(1)
Unrealized gains	—	1
Interest expense	$—	$—

We do not have any derivative financial instruments that qualify as a hedge of a net investment.

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The following tables represent, by commodity type, our net long or short positions that are expected to partially or entirely settle in each respective year. To the extent that we have long dated derivative positions that span multiple calendar years, the contract will appear in more than one line item in the tables below.

	March 31, 2015			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net (Short) Position (Bbls)	Net (Short) Position (MMBtu)	Net (Short) Position (Bbls)	Net Long Position (MMBtu)
2015	(561,825)	(12,429,125)	(4,231,200)	2,675,000
2016	(561,922)	(5,668,564)	(813,267)	1,690,000
2017	—	(6,387,500)	—	—

	March 31, 2014			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net (Short) Position (Bbls)	Net (Short) Position (MMBtu)	Net (Short) Position (Bbls)	Net Long Position (MMBtu)
2014	(520,575)	(4,014,200)	(4,602,350)	4,305,000
2015	(745,695)	(13,458,975)	(5,691,570)	2,185,000
2016	(561,922)	(3,668,564)	(813,267)	—
2017	—	(6,387,500)	—	—

11. Partnership Equity and Distributions

During the three months ended March 31, 2015, we issued 788,033 common units pursuant to our 2014 equity distribution agreement and received proceeds of $31 million, net of commissions and accrued offering costs of less than $1 million, which were used to finance growth opportunities and for general partnership purposes. As of March 31, 2015, approximately $349 million remained available for sale pursuant to our 2014 equity distribution agreement.

In March 2014, we issued 14,375,000 common units to the public at $48.90 per unit. We received proceeds of $677 million, net of offering costs.

In March 2014, we issued 4,497,158 common units to DCP Midstream, LLC as partial consideration for the March 2014 Transactions.

The following table presents our cash distributions paid in 2015 and 2014:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
February 13, 2015	$0.7800	$120
November 14, 2014	$0.7700	$117
August 14, 2014	$0.7575	$111
May 15, 2014	$0.7450	$106
February 14, 2014	$0.7325	$86

12. Net Income or Loss per Limited Partner Unit

Basic and diluted net income or loss per limited partner unit, or LPU, is calculated by dividing net income or loss allocable to limited partners, by the weighted-average number of outstanding LPUs during the period. Diluted net income or loss per LPU is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Dilutive potential units include outstanding awards under our Long-Term Incentive Plan. The dilutive effect of unit-based awards was 11,573, and 9,742 equivalent units during the three months ended March 31, 2015 and 2014, respectively.

13. Commitments and Contingent Liabilities

Litigation — We are not a party to any significant legal proceedings, but are a party to various administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect on our consolidated results of operations, financial position, or cash flow.

Environmental — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities incorporates compliance with environmental laws and regulations and safety standards. In addition, there is increasing focus, from city, state and federal regulatory officials and through litigation, on hydraulic fracturing and the real or perceived environmental impacts of this technique, which indirectly presents some risk to our available supply of natural gas. Failure to comply with these various health, safety and environmental laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our condensed consolidated results of operations, financial position or cash flows.

14. Business Segments

Our operations are located in the United States and are organized into three reporting segments: Natural Gas Services; NGL Logistics; and Wholesale Propane Logistics. Our chief operating decision maker regularly reviews financial information about our operating segments, which are aggregated into the reporting units presented, in deciding how to allocate resources and evaluate performance.

Natural Gas Services — Our Natural Gas Services segment provides services that include gathering, compressing, treating, processing, transporting and storing natural gas, and fractionating NGLs. The segment consists of our Eagle Ford system, East Texas system, Southeast Texas system, Michigan system, Northern Louisiana system, Southern Oklahoma system, Wyoming system, DJ Basin system, 75% interest in the Piceance system and 40% interest in Discovery.

NGL Logistics — Our NGL Logistics segment provides services that include transportation, storage and fractionation of NGLs. The segment consists of our storage facility in Michigan, the DJ Basin fractionators, 12.5% interest in the Mont Belvieu Enterprise fractionator, 20% interest in the Mont Belvieu 1 fractionator, 10% interest in the Texas Express intrastate pipeline, 15% interest in the Panola intrastate pipeline, 33.33% interests in the Southern Hills, Sand Hills and Front Range pipelines, the Black Lake and Wattenberg interstate pipelines and the Seabreeze and Wilbreeze intrastate pipelines.

Wholesale Propane Logistics — Our Wholesale Propane Logistics segment provides services that include the receipt of propane and other liquefied petroleum gases by pipeline, rail or ship to our terminals that store and deliver the product to distributors. The segment consists of 6 rail terminals, one marine terminal, one pipeline terminal and access to several open-access pipeline terminals.

These segments are monitored separately by management for performance against our internal forecast and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the operations of each segment.

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The following tables set forth our segment information:
Three Months Ended March 31, 2015:

	Natural Gas Services	NGL Logistics	Wholesale Propane Logistics	Other	Total
	(Millions)				
Total operating revenue	$440	$18	$110	$—	$568
Gross margin (a)	$119	$18	$29	$—	$166
Operating and maintenance expense	(40)	(4)	(3)	—	(47)
Depreciation and amortization expense	(26)	(2)	(1)	—	(29)
General and administrative expense	—	—	—	(21)	(21)
Earnings from unconsolidated affiliates	(2)	25	—	—	23
Interest expense	—	—	—	(22)	(22)
Income tax expense	—	—	—	(1)	(1)
Net income (loss)	$51	$37	$25	$(44)	$69
Net income attributable to noncontrolling interests	—	—	—	—	—
Net income (loss) attributable to partners	$51	$37	$25	$(44)	$69
Non-cash derivative mark-to-market (b)	$(45)	$—	$3	$(1)	$(43)
Non-cash lower of cost or market adjustments	$3	$—	$1	$—	$4
Capital expenditures	$50	$13	$2	$—	$65
Investments in unconsolidated affiliates	$12	$13	$—	$—	$25

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Three Months Ended March 31, 2014:

	Natural Gas Services (c)	NGL Logistics	Wholesale Propane Logistics	Other	Total
	(Millions)				
Total operating revenue	$849	$17	$215	$—	$1,081
Gross margin (a)	$164	$17	$15	$—	$196
Operating and maintenance expense	(38)	(4)	(3)	—	(45)
Depreciation and amortization expense	(24)	(1)	(1)	—	(26)
General and administrative expense	—	—	—	(16)	(16)
Other expense	(1)	—	—	—	(1)
Earnings from unconsolidated affiliates	(1)	4	—	—	3
Interest expense	—	—	—	(19)	(19)
Income tax expense	—	—	—	(3)	(3)
Net income (loss)	$100	$16	$11	$(38)	$89
Net income attributable to noncontrolling interests	(10)	—	—	—	(10)
Net income (loss) attributable to partners	$90	$16	$11	$(38)	$79
Non-cash derivative mark-to-market (b)	$(12)	$—	$(1)	$(1)	$(14)
Non-cash lower of cost or market adjustments	$—	$—	$3	$—	$3
Capital expenditures	$55	$4	$4	$—	$63
Acquisition expenditures	$100	$669	$—	$—	$769
Investments in unconsolidated affiliates	$42	$23	$—	$—	$65

	March 31, 2015	December 31, 2014
	(Millions)	
Segment long-term assets:		
Natural Gas Services	$4,364	$3,609
NGL Logistics	651	1,364
Wholesale Propane Logistics	121	118
Other (d)	38	58
Total long-term assets	5,174	5,149
Current assets	470	590
Total assets	$5,644	$5,739

(a) Gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas, propane and NGLs. Gross margin is viewed as a non-GAAP measure under the rules of the SEC, but is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales versus product purchases. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

(b) Non-cash commodity derivative mark-to-market is included in gross margin, along with cash settlements for our commodity derivative contracts.

(c)

The segment information for the three months ended March 31, 2014 includes the results of our Lucerne 1 plant. This transfer of net assets between entities under common control was accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information, similar to the pooling method.

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(d) Other long-term assets not allocable to segments consist of unrealized gains on derivative instruments, corporate leasehold improvements and other long-term assets.

15. Supplemental Cash Flow Information

	Three Months Ended March 31,	
	2015	2014
	(Millions)	
Cash paid for interest:		
Cash paid for interest, net of amounts capitalized	$8	$10
Non-cash investing and financing activities:		
Property, plant and equipment acquired with accounts payable	$32	$12
Other non-cash changes in property, plant and equipment	$—	$—
Non-cash addition of investment in unconsolidated affiliates and property, plant and equipment acquired in March 2014 Transactions	$—	$81
Non-cash excess purchase price in March 2014 Transactions and March 2013 Eagle Ford system transaction	$—	$144

16. Supplementary Information — Condensed Consolidating Financial Information
The following condensed consolidating financial information presents the results of operations, financial position and cash flows of DCP Midstream Partners, LP, or parent guarantor, DCP Midstream Operating LP, or subsidiary issuer, which is a 100% owned subsidiary, and non-guarantor subsidiaries, as well as the consolidating adjustments necessary to present DCP Midstream Partners, LP's results on a consolidated basis. The parent guarantor has agreed to fully and unconditionally guarantee debt securities of the subsidiary issuer. For the purpose of the following financial information, investments in subsidiaries are reflected in accordance with the equity method of accounting. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities.

DCP MIDSTREAM PARTNERS, LP
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	Condensed Consolidating Balance Sheet March 31, 2015				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
ASSETS					
Current assets:					
Cash and cash equivalents	$—	$32	$ 1	$—	$33
Accounts receivable, net	—	—	203	—	203
Inventories	—	—	36	—	36
Other	—	—	198	—	198
Total current assets	—	32	438	—	470
Property, plant and equipment, net	—	—	3,374	—	3,374
Goodwill and intangible assets, net	—	—	271	—	271
Advances receivable — consolidated subsidiaries	2,521	1,946	—	(4,467)	—
Investments in consolidated subsidiaries	453	803	—	(1,256)	—
Investments in unconsolidated affiliates	—	—	1,481	—	1,481
Other long-term assets	—	17	31	—	48
Total assets	$2,974	$2,798	$ 5,595	$(5,723)	$5,644
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$—	$283	$ 242	$—	$525
Advances payable — consolidated subsidiaries	—	—	4,467	(4,467)	—
Long-term debt	—	2,062	—	—	2,062
Other long-term liabilities	—	—	51	—	51
Total liabilities	—	2,345	4,760	(4,467)	2,638
Commitments and contingent liabilities					
Equity:					
Partners’ equity:					
Net equity	2,974	456	808	(1,256)	2,982
Accumulated other comprehensive loss	—	(3)	(5)	—	(8)
Total partners’ equity	2,974	453	803	(1,256)	2,974
Noncontrolling interests	—	—	32	—	32
Total equity	2,974	453	835	(1,256)	3,006
Total liabilities and equity	$2,974	$2,798	$ 5,595	$(5,723)	$5,644

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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	Condensed Consolidating Balance Sheet December 31, 2014				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
ASSETS					
Current assets:					
Cash and cash equivalents	$—	$24	$1	$—	$25
Accounts receivable, net	—	—	270	—	270
Inventories	—	—	63	—	63
Other	—	—	232	—	232
Total current assets	—	24	566	—	590
Property, plant and equipment, net	—	—	3,347	—	3,347
Goodwill and intangible assets, net	—	—	274	—	274
Advances receivable — consolidated subsidiaries	2,610	1,962	—	(4,572)	—
Investments in consolidated subsidiaries	383	712	—	(1,095)	—
Investments in unconsolidated affiliates	—	—	1,459	—	1,459
Other long-term assets	—	17	52	—	69
Total assets	$2,993	$2,715	$5,698	$(5,667)	$5,739
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$—	$271	$330	$—	$601
Advances payable — consolidated subsidiaries	—	—	4,572	(4,572)	—
Long-term debt	—	2,061	—	—	2,061
Other long-term liabilities	—	—	51	—	51
Total liabilities	—	2,332	4,953	(4,572)	2,713
Commitments and contingent liabilities					
Equity:					
Partners’ equity:					
Net equity	2,993	387	717	(1,095)	3,002
Accumulated other comprehensive loss	—	(4)	(5)	—	(9)
Total partners’ equity	2,993	383	712	(1,095)	2,993
Noncontrolling interests	—	—	33	—	33
Total equity	2,993	383	745	(1,095)	3,026
Total liabilities and equity	$2,993	$2,715	$5,698	$(5,667)	$5,739

DCP MIDSTREAM PARTNERS, LP
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Condensed Consolidating Statement of Operations
Three Months Ended March 31, 2015

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$—	$—	$470	$—	$470
Transportation, processing and other	—	—	79	—	79
Gains from commodity derivative activity, net	—	—	19	—	19
Total operating revenues	—	—	568	—	568
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	402	—	402
Operating and maintenance expense	—	—	47	—	47
Depreciation and amortization expense	—	—	29	—	29
General and administrative expense	—	—	21	—	21
Total operating costs and expenses	—	—	499	—	499
Operating income	—	—	69	—	69
Interest expense, net	—	(22)	—	—	(22)
Income from consolidated subsidiaries	69	91	—	(160)	—
Earnings from unconsolidated affiliates	—	—	23	—	23
Income before income taxes	69	69	92	(160)	70
Income tax expense	—	—	(1)	—	(1)
Net income	69	69	91	(160)	69
Net income attributable to noncontrolling interests	—	—	—	—	—
Net income attributable to partners	$69	$69	$91	$(160)	$69

Condensed Consolidating Statement of Comprehensive Income
Three Months Ended March 31, 2015

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Net income	$69	$69	$ 91	$(160)	$69
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	1	—	—	1
Other comprehensive income from consolidated subsidiaries	1	—	—	(1)	—
Total other comprehensive income	1	1	—	(1)	1
Total comprehensive income	70	70	91	(161)	70
	—	—	—	—	—

Total comprehensive income attributable to noncontrolling interests					
Total comprehensive income attributable to partners	$70	$70	$ 91	$(161)	$70

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three Months Ended March 31, 2015 and 2014 - (Continued)
(Unaudited)

	Condensed Consolidating Statement of Operations Three Months Ended March 31, 2014 (a)				
	Parent Guarantor (Millions)	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$—	$—	$ 1,013	$—	$1,013
Transportation, processing and other	—	—	83	—	83
Gains from commodity derivative activity, net	—	—	(15)	—	(15)
Total operating revenues	—	—	1,081	—	1,081
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	885	—	885
Operating and maintenance expense	—	—	45	—	45
Depreciation and amortization expense	—	—	26	—	26
General and administrative expense	—	—	16	—	16
Other expense	—	—	1	—	1
Total operating costs and expenses	—	—	973	—	973
Operating income	—	—	108	—	108
Interest expense	—	(19)	—	—	(19)
Earnings from unconsolidated affiliates	—	—	3	—	3
Income from consolidated subsidiaries	79	98	—	(177)	—
Income before income taxes	79	79	111	(177)	92
Income tax expense	—	—	(3)	—	(3)
Net income	79	79	108	(177)	89
Net income attributable to noncontrolling interests	—	—	(10)	—	(10)
Net income attributable to partners	$79	$79	$ 98	$(177)	$79

(a) The financial information for the three months ended March 31, 2014 includes the results of our Lucerne 1 plant, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior periods are retrospectively adjusted to furnish comparative information similar to the pooling method.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three Months Ended March 31, 2015 and 2014 - (Continued)
(Unaudited)

	Condensed Consolidating Statement of Comprehensive Income Three Months Ended March 31, 2014 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Net income	$79	$79	$ 108	$(177)	$89
Other comprehensive income:					
Reclassification of cash flow hedge losses into earnings	—	2	—	—	2
Other comprehensive income from consolidated subsidiaries	2	—	—	(2)	—
Total other comprehensive income	2	2	—	(2)	2
Total comprehensive income	81	81	108	(179)	91
Total comprehensive income attributable to noncontrolling interests	—	—	(10)	—	(10)
Total comprehensive income attributable to partners	$81	$81	$ 98	$(179)	$81

(a) The financial information for the three months ended March 31, 2014 includes the results of our Lucerne 1 plant, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior periods are retrospectively adjusted to furnish comparative information similar to the pooling method.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three Months Ended March 31, 2015 and 2014 - (Continued)
(Unaudited)

	Condensed Consolidating Statement of Cash Flows Three Months Ended March 31, 2015				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	—	(8)	196	—	188
INVESTING ACTIVITIES:					
Intercompany transfers	89	16	—	(105)	—
Capital expenditures	—	—	(65)	—	(65)
Investments in unconsolidated affiliates	—	—	(25)	—	(25)
Net cash used in investing activities	89	16	(90)	(105)	(90)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	(105)	105	—
Proceeds from long-term debt	—	162	—	—	162
Payments of long-term debt	—	(162)	—	—	(162)
Proceeds from issuance of common units, net of offering costs	31	—	—	—	31
Distributions to limited partners and general partner	(120)	—	—	—	(120)
Distributions to noncontrolling interests	—	—	(1)	—	(1)
Net cash used in financing activities	(89)	—	(106)	105	(90)
Net change in cash and cash equivalents	—	8	—	—	8
Cash and cash equivalents, beginning of period	—	24	1	—	25
Cash and cash equivalents, end of period	—	32	1	—	33

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three Months Ended March 31, 2015 and 2014 - (Continued)
(Unaudited)

Condensed Consolidating Statements of Cash Flows
Three Months Ended March 31, 2014 (a)

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$—	$(11)	$ 157	$—	$146
INVESTING ACTIVITIES:					
Intercompany transfers	(591)	(365)	—	956	—
Capital expenditures	—	—	(63)	—	(63)
Acquisitions, net of cash acquired	—	—	(100)	—	(100)
Acquisition of unconsolidated affiliates	—	—	(669)	—	(669)
Investments in unconsolidated affiliates	—	—	(65)	—	(65)
Proceeds from sale of assets	—	—	1	—	1
Net cash used in investing activities	(591)	(365)	(896)	956	(896)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	956	(956)	—
Proceeds from long-term debt	—	719	—	—	719
Payments of long-term debt	—	(314)	—	—	(314)
Payment of deferred financing costs	—	(6)	—	—	(6)
Proceeds from issuance of common units, net of offering costs	677	—	—	—	677
Excess purchase price over acquired interests and commodity hedges	—	—	(14)	—	(14)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	(6)	—	(6)
Distributions to limited partners and general partner	(86)	—	—	—	(86)
Distributions to noncontrolling interests	—	—	(10)	—	(10)
Purchase of additional interest in a subsidiary	—	—	(198)	—	(198)
Contributions from noncontrolling interests	—	—	3	—	3
Net cash provided by financing activities	591	399	731	(956)	765
Net change in cash and cash equivalents	—	23	(8)	—	15
Cash and cash equivalents, beginning of period	—	—	12	—	12
Cash and cash equivalents, end of period	$—	$23	$ 4	$—	$27

(a) The financial information for the three months ended March 31, 2014 includes the results of our Lucerne 1 plant, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior periods are retrospectively adjusted to furnish comparative information similar to the pooling method.

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DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three Months Ended March 31, 2015 and 2014 - (Continued)
(Unaudited)

17. Subsequent Events

On April 28, 2015, we announced that the board of directors of the General Partner declared a quarterly distribution of $0.78 per unit. The distribution will be paid on May 15, 2015 to unitholders of record on May 8, 2015.

In April 2015, we filed a new universal shelf registration statement with the SEC, that became effective upon filing, in order to replace an existing shelf registration statement that was set to expire. As with the expiring shelf registration statement, the new universal shelf registration statement also allows us to issue an unlimited amount of common units and debt securities. We have issued no common units or debt securities under this registration statement.

Table of Contents

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our condensed consolidated financial statements and notes included elsewhere in this quarterly report and the consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2014.

Overview

We are a Delaware limited partnership formed by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. Our operations are organized into three business segments: Natural Gas Services, NGL Logistics and Wholesale Propane Logistics.

Our business is impacted by commodity prices, which we mitigate on an overall Partnership basis through a hedging program on volumes of throughput and sales of natural gas, NGLs and condensate through 2015. Various factors impact both commodity prices and volumes, and as indicated in Item 3. "Quantitative and Qualitative Disclosures about Market Risk," we have sensitivities to certain cash and non-cash changes in commodity prices. In late 2014, commodity prices declined substantially and experienced significant volatility. Commodity prices have remained weak in the first part of 2015 relative to historical prices. If commodity prices remain weak for a sustained period, our natural gas throughput and NGL volumes may be impacted, particularly as producers are curtailing or redirecting drilling. Drilling activity levels vary by geographic area, but in general, we have observed widespread decreases in drilling activity with lower commodity prices. The number of active oil and gas drilling rigs in the United States has significantly decreased, from 1,839 in December 2014 to 1,046 at March 31, 2015 (Source: Baker Hughes). Furthermore, a sustained decline in commodity prices could result in a decrease in exploration and development activities in the fields served by our gas gathering and residue gas and NGL pipeline transportation systems, and our natural gas treating and processing plants, which could lead to reduced utilization of these assets. Despite recent short-term weakness, our long-term view is that commodity prices will be at levels that we believe will support continued growth in natural gas, condensate and NGL production.

NGL prices are impacted by the demand from petrochemical and refining industries and export facilities. The petrochemical industry has been making significant investment in building or expanding facilities to convert chemical plants from a heavier oil-based feedstock to lighter NGL-based feedstocks, including ethane. This increased demand in future years should provide support for the increasing supply of ethane. Prior to those facilities commencing operations, ethane prices could remain weak with supply in excess of demand. In addition, export facilities are being expanded or built, which provide support for the increasing supply of NGLs. Although there can be, and has been, near-term volatility in NGL prices, longer term we believe there will be sufficient demand in NGLs to support increasing supply.

In addition to the U.S. financial markets, many businesses and investors continue to monitor global economic conditions. Uncertainty abroad may contribute to volatility in domestic financial and commodity markets. In addition, we could be entering a period of sustained, lower commodity prices.

We plan for these cyclical downturns in commodity prices and we believe we are positioned to withstand current and future commodity price volatility as a result of the following:

- Our direct commodity hedged positions mitigate a portion of our commodity price risk through 2017, with the majority of our positions settling through the first quarter of 2016. Additionally, our fee-based business represents a significant portion of our estimated margins.
- We have positive operating cash flow from our well-positioned and diversified assets.
- We work to prudently manage our capital spend as well as focus on fee-based growth projects.
- We have a strong capital structure and balance sheet.
- We believe we have solid access to capital.

Increased activity levels in liquids rich gas basins combined with access to capital markets at relatively low costs have historically enabled us to execute our multi-faceted growth strategy. Our multi-faceted growth strategy may take numerous forms such as organic build opportunities within our footprint, dropdown opportunities from DCP

Midstream, LLC, joint venture opportunities, and third-party acquisitions. In 2015, we will continue to prudently execute our multi-faceted growth strategy.

Some of our recent growth projects include the following:

- The expansion of Discovery's Keathley Canyon natural gas gathering pipeline system was placed into service in the first quarter of 2015.
- The construction of our Lucerne 2 plant is progressing on schedule and is expected to be completed in the second quarter of 2015.
- In January 2015, we acquired a 15% interest in the Panola intrastate NGL pipeline which is currently undergoing an expansion that is expected to be completed in the first quarter of 2016.
- In March 2015, we began construction for a gathering system in the DJ Basin, or the Grand Parkway gathering project, that is expected to be complete by the end of 2015.

In April 2015, we filed a new universal shelf registration statement with the Securities and Exchange Commission, or SEC, that became effective upon filing, in order to replace an existing shelf registration statement that was set to expire. As with the expiring shelf registration statement, the new universal shelf registration statement also allows us to issue an unlimited amount of common units and debt securities. We have issued no common units or debt securities under this registration statement. During the three months ended March 31, 2015, we received net proceeds of $31 million from the issuance of our common units to the public under our 2014 equity distribution agreement. As of March 31, 2015, the unused capacity under the Amended and Restated Credit Agreement was $1,249 million, of which $1,205 million was available for general working capital purposes, providing liquidity to continue to execute on our growth plans. In the first quarter of 2015, our credit rating was lowered below investment grade. As a result of this ratings action, interest rates under the Amended and Restated Credit Agreement increased and we no longer have the ability to utilize our Commercial Paper Program.

We announced a quarterly distribution of $0.78 per unit for the first quarter of 2015, resulting in an approximately 4.7% increase in our quarterly distribution rate over the rate declared for the first quarter of 2014. This distribution remains unchanged from the previous quarter and reflects the current industry environment and the partnership’s approach to sustainable ongoing distributions.

General Trends and Outlook

During 2015, our strategic objectives will continue to focus on maintaining stable distributable cash flows from our existing assets and executing on growth opportunities to increase our long-term distributable cash flows. We believe the key elements to stable distributable cash flows are the diversity of our asset portfolio, our fee-based business which represents a significant portion of our estimated margins, plus our hedged commodity position, the objective of which is to protect against downside risk in our distributable cash flows.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $50 million and $60 million, and approved expenditures for expansion capital of approximately $300 million, for the year ending December 31, 2015. Expansion capital expenditures include construction of the Lucerne 2 plant, the Grand Parkway gathering project and expansion of the Panola pipeline, which will be shown as an investment in unconsolidated affiliates in our condensed consolidated statements of cash flows. The board of directors of our General Partner may, at its discretion, approve additional growth and maintenance capital during the year.

For an in-depth discussion of factors that may significantly affect our results, see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations -- Factors That May Significantly Affect Our Results” included in our Annual Report on Form 10-K for the year ended December 31, 2014.

Reconciliation of Non-GAAP Measures

Gross Margin and Segment Gross Margin — We view our gross margin as an important performance measure of the core profitability of our operations. We review our gross margin monthly for consistency and trend analysis.

We define gross margin as total operating revenues, including commodity derivative activity, less purchases of natural gas, propane and NGLs, and we define segment gross margin for each segment as total operating revenues, including commodity derivative activity, for that segment less commodity purchases for that segment. Our gross margin equals the sum of our segment gross margins. Gross margin and segment gross margin are primary performance measures used by management, as these measures represent the results of product sales and purchases, a key component of our operations. As an indicator of our operating performance, gross margin and segment gross margin should not be considered an alternative to, or more meaningful than, operating revenues, net income or loss, net income or loss attributable to partners, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with accounting principles generally accepted in the United States of America, or GAAP.

Adjusted EBITDA — We define adjusted EBITDA as net income or loss attributable to partners less interest income, noncontrolling interest in depreciation and income tax expense and non-cash commodity derivative gains, plus interest expense, income tax expense, depreciation and amortization expense and non-cash commodity derivative losses. Our adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate this measure in the same manner.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or loss, net income or loss attributable to partners, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance, liquidity or ability to service debt obligations.

Adjusted EBITDA is used as a supplemental liquidity and performance measure and adjusted segment EBITDA is used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing methods or capital structure;
- viability and performance of acquisitions and capital expenditure projects and the overall rates of return on investment opportunities; and
- in the case of Adjusted EBITDA, the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, make cash distributions to our unitholders and general partner, and finance maintenance capital expenditures.

Adjusted Segment EBITDA — We define adjusted segment EBITDA for each segment as segment net income or loss attributable to partners less non-cash commodity derivative gains for that segment, plus depreciation and amortization expense and non-cash commodity derivative losses for that segment, adjusted for any noncontrolling interest on depreciation and amortization expense for that segment. Our adjusted segment EBITDA may not be comparable to similarly titled measures of other companies because they may not calculate adjusted segment EBITDA in the same manner.

Adjusted segment EBITDA should not be considered in isolation or as an alternative to our financial measures presented in accordance with GAAP, including operating revenues, net income or loss attributable to Partners, or any other measure of performance presented in accordance with GAAP.

The accompanying schedules provide reconciliations of gross margin, segment gross margin and adjusted segment EBITDA to its most directly comparable GAAP financial measure.

Distributable Cash Flow — We define Distributable Cash Flow as net cash provided by or used in operating activities, less maintenance capital expenditures, net of reimbursable projects, plus or minus adjustments for non-cash mark-to-market of derivative instruments, proceeds from divestiture of assets, net income attributable to noncontrolling interest net of depreciation and income tax, net changes in operating assets and liabilities, and other adjustments to reconcile net cash provided by or used in operating activities. Maintenance capital expenditures are cash expenditures made to maintain our cash flows, operating or earnings capacity. These expenditures add on to or improve capital assets owned, including certain system integrity, compliance and safety improvements. Maintenance capital expenditures also include certain well connects, and may include the acquisition or construction of new capital assets. Non-cash mark-to-market of derivative instruments is considered to be non-cash for the purpose of computing Distributable Cash Flow because settlement will not occur until future periods, and will be impacted by future changes in commodity prices and interest rates. Distributable Cash Flow is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our ability to make cash distributions to our unitholders and our general partner.

Our Distributable Cash Flow may not be comparable to a similarly titled measure of another company because other entities may not calculate Distributable Cash Flow in the same manner. Our gross margin, segment gross margin, adjusted EBITDA and adjusted segment EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate these measures in the same manner. The following table sets forth our reconciliation of certain non-GAAP measures:

Reconciliation of Non-GAAP Measures	Three Months Ended March 31, 2015 (Millions)	2014
Reconciliation of net income attributable to partners to gross margin:		
Net income attributable to partners	$69	$79
Interest expense	22	19
Income tax expense	1	3
Operating and maintenance expense	47	45
Depreciation and amortization expense	29	26
General and administrative expense	21	16
Other expense	—	1
Earnings from unconsolidated affiliates	(23)	(3)
Net income attributable to noncontrolling interests	—	10
Gross margin	$166	$196
Non-cash commodity derivative mark-to-market (a)	$(42)	$(13)
Reconciliation of segment net income attributable to partners to segment gross margin:		
Natural Gas Services segment:		
Segment net income attributable to partners	$51	$90
Operating and maintenance expense	40	38
Depreciation and amortization expense	26	24
Other expense	—	1
Earnings from unconsolidated affiliates	2	1
Net income attributable to noncontrolling interests	—	10
Segment gross margin	$119	$164
Non-cash commodity derivative mark-to-market (a)	$(45)	$(12)
NGL Logistics segment:		
Segment net income attributable to partners	$37	$16
Operating and maintenance expense	4	4
Depreciation and amortization expense	2	1
Earnings from unconsolidated affiliates	(25)	(4)
Segment gross margin	$18	$17
Wholesale Propane Logistics segment:		
Segment net income attributable to partners	$25	$11
Operating and maintenance expense	3	3
Depreciation and amortization expense	1	1
Segment gross margin	$29	$15
Non-cash commodity derivative mark-to-market (a)	$3	$(1)

(a) Non-cash commodity derivative mark-to-market is included in gross margin and segment gross margin, along with cash settlements for our commodity derivative contracts.

	Three Months Ended March 31, 2015	2014
	(Millions)	
Reconciliation of net income attributable to partners to adjusted segment EBITDA:		
Natural Gas Services segment:		
Segment net income attributable to partners (a)	$51	$90
Non-cash commodity derivative mark-to-market	45	12
Depreciation and amortization expense	26	24
Noncontrolling interest on depreciation and income tax	(1)	(2)
Adjusted Segment EBITDA	$121	$124
NGL Logistics segment:		
Segment net income attributable to partners	$37	$16
Depreciation and amortization expense	2	1
Adjusted Segment EBITDA	$39	$17
Wholesale Propane Logistics segment:		
Segment net income attributable to partners (b)	$25	$11
Non-cash commodity derivative mark-to-market	(3)	1
Depreciation and amortization expense	1	1
Adjusted Segment EBITDA	$23	$13

(a) Includes $3 million in lower of cost or market adjustments for the three months ended March 31, 2015. There were no lower of cost or market adjustments for the three months ended March 31, 2014.

(b) Includes $1 million and $3 million in lower of cost or market adjustments for the three months ended March 31, 2015 and 2014, respectively.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Critical Accounting Policies and Estimates within Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 2 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data” in our Annual Report on Form 10-K for the year ended December 31, 2014. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three months ended March 31, 2015 are the same as those described in our Annual Report on Form 10-K for the year ended December 31, 2014. Certain information and note disclosures normally included in our annual financial statements prepared in accordance with GAAP have been condensed or omitted from the interim financial statements included in this Quarterly Report on Form 10-Q pursuant to the rules and regulations of the SEC, although we believe that the disclosures made are adequate to make the information not misleading. The unaudited condensed consolidated financial statements and other information included in this Quarterly Report on Form 10-Q should be read in conjunction with the audited consolidated financial statements and notes thereto in our Annual Report on Form 10-K for the year ended December 31, 2014.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our condensed consolidated results of operations for the three months ended March 31, 2015 and 2014. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Three Months Ended March 31,		Variance 2015 vs. 2014	
	2015	(a) 2014	Increase (Decrease)	Percent
	(Millions, except operating data)			
Operating revenues (b):				
Natural Gas Services	$440	$849	$(409)	(48)%
NGL Logistics	18	17	1	6%
Wholesale Propane Logistics	110	215	(105)	(49)%
Total operating revenues	568	1,081	(513)	(47)%
Gross margin (c):				
Natural Gas Services	119	164	(45)	(27)%
NGL Logistics	18	17	1	6%
Wholesale Propane Logistics	29	15	14	93%
Total gross margin	166	196	(30)	(15)%
Operating and maintenance expense	(47)	(45)	2	4%
Depreciation and amortization expense	(29)	(26)	3	12%
General and administrative expense	(21)	(16)	5	31%
Other expense	—	(1)	(1)	(100)%
Earnings from unconsolidated affiliates (d)	23	3	20	667%
Interest expense	(22)	(19)	3	16%
Income tax expense	(1)	(3)	(2)	(67)%
Net income attributable to noncontrolling interests	—	(10)	(10)	(100)%
Net income attributable to partners	$69	$79	$(10)	(13)%
Other data:				
Non-cash commodity derivative mark-to-market	$(42)	$(13)	$29	223%
Natural gas throughput (MMcf/d) (e)	2,631	2,373	258	11%
NGL gross production (Bbls/d) (e)	151,024	138,827	12,197	9%
NGL pipelines throughput (Bbls/d) (e)	252,191	92,275	159,916	173%
NGL fractionator throughput (Bbls/d) (e)	51,992	55,218	(3,226)	(6)%
Propane sales volume (Bbls/d)	30,614	32,049	(1,435)	(4)%

(a) Includes the results of our Lucerne 1 plant, retrospectively adjusted, which we acquired on March 28, 2014.

(b) Operating revenues include the impact of commodity derivative activity.

(c) Gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas, propane and NGLs. Segment gross margin for each segment consists of total operating revenues for that segment, including commodity derivative activity, less commodity purchases for that segment. Please read “Reconciliation of Non-GAAP Measures” above.

(d) Includes our share, based on our ownership percentage, of the earnings of all unconsolidated affiliates which include our 40% ownership of Discovery, our 33.33% ownership of each of the Sand Hills, Southern Hills and Front Range NGL pipelines, 20% ownership of the Mont Belvieu 1 fractionator, 12.5% ownership of the Mont Belvieu Enterprise fractionator and 10% ownership of the Texas Express NGL pipeline. Earnings for Discovery, Sand Hills, Southern Hills, Front Range, Mont Belvieu 1 and Texas Express include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the entities.

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(e) Includes our share, based on our ownership percentage, of the throughput volumes and NGL production of unconsolidated affiliates.

Three Months Ended March 31, 2015 vs. Three Months Ended March 31, 2014

Total Operating Revenues — Total operating revenues decreased $513 million in 2015 compared to 2014 primarily as a result of the following:

- $409 million decrease for our Natural Gas Services segment primarily due to decreased commodity prices, lower NGL sales volumes which impact both sales and purchases, lower volumes at our natural gas storage and pipeline assets at the Southeast Texas system, a change in the contract structure at our Lucerne 1 plant and a decrease in fee revenue, partially offset by favorable commodity derivative activity; and
- $105 million decrease for our Wholesale Propane Logistics segment primarily due to lower propane prices and volumes, partially offset by a new agreement with an existing customer.

Gross Margin — Gross margin decreased $30 million in 2015 compared to 2014 primarily as a result of the following:

- $45 million decrease for our Natural Gas Services segment primarily related to lower commodity prices, lower unit margins on our storage assets, a favorable contractual producer settlement in 2014 and non-cash lower of cost or market inventory adjustments; partially offset by favorable commodity derivative activity and higher valued product mix.

This decrease was partially offset by:

- $14 million increase for our Wholesale Propane Logistics segment primarily due to a partial recovery of non-cash lower of cost or market inventory adjustments recognized in the fourth quarter of 2014, higher unit margins, the conversion of one of our assets to a butane export facility and a decrease in non-cash lower of cost or market inventory adjustments, partially offset by a decrease in volumes as discussed below under the heading "Propane Sales Volumes".

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2015 compared to 2014 primarily as a result of growth in our operations.

General and Administrative Expense — General and administrative expense increased in 2015 compared to 2014 primarily as a result of an increase in the annual fee under our services agreement with DCP Midstream, LLC.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2015 compared to 2014 primarily as a result of the March 2014 contribution of Sand Hills and Southern Hills and increased volumes at Front Range in our NGL Logistics segment.

Interest Expense — Interest expense increased in 2015 compared to 2014 as a result of higher average outstanding debt balances associated with the growth in our operations.

Income Tax Expense — Income tax expense decreased in 2015 compared to 2014 primarily due to a decrease in net income.

Net Income Attributable to Noncontrolling Interests — Net income attributable to noncontrolling interests decreased in 2015 compared to 2014 primarily as a result of the contribution of the remaining 20% interest in the Eagle Ford system in March 2014.

Results of Operations — Natural Gas Services Segment

The results of operations for our Natural Gas Services segment are as follows:

	Three Months Ended March 31,		Variance 2015 vs. 2014	
	2015	(a) 2014	Increase (Decrease)	Percent
	(Millions, except operating data)			
Operating revenues:				
Sales of natural gas, NGLs and condensate	$363	$798	$(435)	(55)%
Transportation, processing and other	58	66	(8)	(12)%
Gains (losses) from commodity derivative activity	19	(15)	*	*
Total operating revenues	440	849	(409)	(48)%
Purchases of natural gas and NGLs	(321)	(685)	(364)	(53)%
Segment gross margin (b)	119	164	(45)	(27)%
Operating and maintenance expense	(40)	(38)	2	5%
Depreciation and amortization expense	(26)	(24)	2	8%
Other expense	—	(1)	(1)	(100)%
Losses from unconsolidated affiliates (c)	(2)	(1)	1	100%
Segment net income	51	100	(49)	(49)%
Segment net income attributable to noncontrolling interests	—	(10)	(10)	(100)%
Segment net income attributable to partners	$51	$90	$(39)	(43)%
Other data:				
Non-cash commodity derivative mark-to-market	$(45)	$(12)	$(33)	(275)%
Natural gas throughput (MMcf/d) (d)	2,631	2,373	258	11%
NGL gross production (Bbls/d) (d)	151,024	138,827	12,197	9%

* Percentage change is not meaningful.

(a) Includes the results of our Lucerne 1 plant, retrospectively adjusted, which we acquired on March 28, 2014.

(b) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas and NGLs. Please read "Reconciliation of Non-GAAP Measures" above.

(c) Includes our share, based on our ownership percentage, of the earnings of all unconsolidated affiliates which include our 40% ownership of Discovery. Earnings for Discovery include the amortization of the net difference between the carrying amount of our investment and the underlying equity of the entity.

(d) Includes our share, based on our ownership percentage, of the throughput volumes and NGL production of unconsolidated affiliates.

Three Months Ended March 31, 2015 vs. Three Months Ended March 31, 2014

Total Operating Revenues — Total operating revenues decreased $409 million in 2015 compared to 2014, primarily as a result of the following:

- $221 million decrease attributable to decreased commodity prices, which impact both sales and purchases, before the impact of commodity derivative activity;
- $112 million decrease primarily attributable to lower NGL sales volumes, which impact both sales and purchases, including the effects of contractual changes, higher ethane rejection and a third party outage.
- $45 million decrease attributable to decreased volumes related to our natural gas storage and pipeline assets at our Southeast Texas system;
- $36 million decrease attributable to decreased prices related to our natural gas storage and pipeline assets at our Southeast Texas and Northern Louisiana systems;
- $18 million decrease attributable to a change in the contract structure at our Lucerne 1 plant whereby revenues changed from a gross presentation to a net fee presentation; and
- $11 million decrease in fee revenue primarily attributable to a favorable contractual producer settlement in 2014 and a third party outage in 2015, partially offset by growth at the O'Connor plant in our DJ Basin system.

These decreases were partially offset by:

- $34 million increase as a result of commodity derivative activity attributable to realized cash settlement gains in 2015 compared to realized cash settlement losses in 2014 for a net increase of $67 million, partially offset by an increase in unrealized commodity derivative losses of $33 million due to movements in forward prices of commodities.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs decreased $364 million in 2015 compared to 2014 primarily as a result of decreased commodity prices, lower NGL sales volumes which impact both sales and purchases, decreased volumes at our natural gas storage and pipeline assets at the Southeast Texas system, a change in the contract structure at our Lucerne 1 plant whereby revenues changed from a gross presentation to a net fee presentation and non-cash lower of cost or market inventory adjustments of $3 million.

Segment Gross Margin — Segment gross margin decreased $45 million in 2015 compared to 2014, primarily as a result of the following:

- $46 million decrease as a result of lower commodity prices;
- $28 million decrease attributable to lower unit margins on our storage assets; and
- $5 million decrease attributable to a favorable contractual producer settlement in 2014 and non-cash lower of cost or market inventory adjustments, partially offset by higher valued product mix.

These decreases were partially offset by:

- $34 million increase as a result of commodity derivative activity as discussed above.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2015 compared to 2014 primarily as a result of growth in our operations.

Segment Net Income Attributable to Noncontrolling Interests - Segment net income attributable to noncontrolling interests decreased in 2015 compared to 2014, primarily as a result of the contribution of the remaining 20% interest in the Eagle Ford system in March 2014.
Natural Gas Throughput - Natural gas throughput increased in 2015 compared to 2014 primarily as a result of the contribution of the remaining 20% interest in the Eagle Ford system in March 2014, the completion of the Keathley Canyon project at Discovery in February 2015 and growth at the O'Connor plant in our DJ Basin system, partially offset by lower volumes across certain assets and a third party outage.
NGL Gross Production - NGL production increased in 2015 compared to 2014 primarily as a result of the contribution of the remaining 20% interest in the Eagle Ford system in March 2014, the completion of the Keathley Canyon project at Discovery in February 2015 and growth at the O'Connor plant in our DJ Basin system, partially offset by lower volumes across certain assets and a third party outage.

Results of Operations — NGL Logistics Segment
The results of operations for our NGL Logistics segment are as follows:

	Three Months Ended March 31,		Variance 2015 vs. 2014	
	2015	2014	Increase (Decrease)	Percent
	(Millions, except operating data)			
Operating revenues:				
Transportation, processing and other	18	17	1	6 %
Total operating revenues and segment gross margin	18	17	1	6 %
Operating and maintenance expense	(4)	(4)	—	— %
Depreciation and amortization expense	(2)	(1)	1	100 %
Earnings from unconsolidated affiliates (a)	25	4	21	525 %
Segment net income attributable to partners	$37	$16	$21	131 %
Other data:				
NGL pipelines throughput (Bbls/d) (b)	252,191	92,275	159,916	173 %
NGL fractionator throughput (Bbls/d) (b)	51,992	55,218	(3,226)	(6)%

(a) Includes our share, based on our ownership percentage, of the earnings of all unconsolidated affiliates which include our 33.33% ownership in each of the Sand Hills and Southern Hills pipelines, which were contributed to us in March 2014, 33.33% ownership of the Front Range pipeline, which commenced operations in February 2014, 20% ownership of the Mont Belvieu 1 fractionator, 12.5% ownership of the Mont Belvieu Enterprise fractionator and 10% ownership of the Texas Express pipeline. Earnings for Sand Hills, Southern Hills, Front Range, Mont Belvieu 1 and Texas Express include the amortization of the net difference between the carrying amount of our investments and the underlying equity of the entities.
(b) Includes our share, based on our ownership percentage, of the throughput volumes of unconsolidated affiliates.

Three Months Ended March 31, 2015 vs. Three Months Ended March 31, 2014

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2015 compared to 2014 primarily as a result of the contribution of Sand Hills and Southern Hills in March 2014 and increased volumes at Front Range which commenced operations in February 2014.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2015 compared to 2014 as a result of volume growth on certain of our pipelines including Sand Hills and Southern Hills which were contributed to us in March 2014, Front Range which commenced operations in February 2014 and Black Lake.

NGL Fractionators Throughput — NGL fractionators throughput decreased in 2015 compared to 2014 as a result of lower volumes due to unfavorable location pricing at our Mont Belvieu fractionators.

Results of Operations — Wholesale Propane Logistics Segment

The results of operations for our Wholesale Propane Logistics segment are as follows:

	Three Months Ended March 31,		Variance 2015 vs. 2014	
	2015	2014	Increase (Decrease)	Percent
	(Millions, except operating data)			
Operating revenues:				
Sales of propane	$107	$215	$(108)	(50)%
Storage, transportation and other	3	—	$3	100%
Total operating revenues	110	215	(105)	(49)%
Purchases of propane	(81)	(200)	(119)	(60)%
Segment gross margin (a)	29	15	14	93%
Operating and maintenance expense	(3)	(3)	—	—%
Depreciation and amortization expense	(1)	(1)	—	—%
Segment net income attributable to partners	$25	$11	$14	127%
Other data:				
Non-cash commodity derivative mark-to-market	$3	$(1)	$4	*
Propane sales volume (Bbls/d)	30,614	32,049	(1,435)	(4)%

* Percentage change is not meaningful.

(a) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of propane. Please read “Reconciliation of Non-GAAP Measures” above.

Three Months Ended March 31, 2015 vs. Three Months Ended March 31, 2014

Total Operating Revenues — Total operating revenues decreased by $105 million in 2015 compared to 2014, primarily as a result of the following:

- $97 million decrease attributable to lower propane prices which impact both sales and purchases; and
- $11 million decrease attributable to decreased volumes as discussed below under the heading "Propane Sales Volumes".

These decreases were partially offset by:

- $3 million increase attributable to a new agreement with an existing customer.

Purchases of Propane — Purchases of propane decreased in 2015 compared to 2014 primarily due to lower propane prices which impact both sales and purchases, colder weather in 2014, the conversion of one of our assets to a butane export facility and a decrease in non-cash lower of cost or market inventory adjustments.

Segment Gross Margin — Segment gross margin increased in 2015 compared to 2014 primarily due to a partial recovery of lower of cost or market inventory adjustments recognized in the fourth quarter of 2014, higher unit margins, the conversion of one of our assets to a butane export facility and a decrease in non-cash lower of cost or market inventory adjustments, partially offset by a decrease in volumes as discussed below under the heading "Propane Sales Volumes".

Commodity Derivative Activity — Non-cash commodity derivative mark-to-market increased primarily due to unrealized commodity derivative losses in 2014 compared to unrealized commodity derivative gains in 2015 due to movements in forward prices of commodities for a net increase of $4 million. This increase was offset by a decrease in realized cash settlement gains of $4 million.

Propane Sales Volume — Propane sales volumes decreased in 2015 compared to 2014 primarily due to colder weather in 2014 and lower propane inventory resulting from the conversion of one of our assets to a butane export facility, partially offset by increases across certain of our assets.

Liquidity and Capital Resources

We expect our sources of liquidity to include:

- cash generated from operations;
- issuance of additional common units, including issuances we may make to DCP Midstream, LLC;
- debt offerings;
- cash distributions from our unconsolidated affiliates;
- borrowings under our Amended and Restated Credit Agreement;
- borrowings under term loans; and
- letters of credit.

We anticipate our more significant uses of resources to include:

- quarterly distributions to our unitholders and general partner;
- growth capital expenditures;
- contributions to our unconsolidated affiliates to finance our share of their capital expenditures;
- business and asset acquisitions, including transactions with DCP Midstream, LLC; and
- collateral with counterparties to our swap contracts to secure potential exposure under these contracts, which may, at times, be significant depending on commodity price movements, and letters of credit we have posted.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure and acquisition requirements, and quarterly cash distributions for the next twelve months. In the event these sources are not sufficient, we would reduce our discretionary spending.

We routinely evaluate opportunities for strategic investments or acquisitions. Future material investments or acquisitions may require that we obtain additional capital, assume third party debt or incur other long-term obligations. We have the option to utilize both equity and debt instruments as vehicles for the long-term financing of our investment activities and acquisitions.

Based on current and anticipated levels of operations, we believe we have adequate committed financial resources to conduct our ongoing business, although deterioration in our operating environment could limit our borrowing capacity, further impact our credit ratings, raise our financing costs, as well as impact our compliance with our financial covenant requirements under the Amended and Restated Credit Agreement.

In May 2014, we entered into the Amended and Restated Credit Agreement, a $1.25 billion amended and restated senior unsecured revolving credit agreement that matures on May 1, 2019. Our borrowing capacity may be limited by the Amended and Restated Credit Agreement’s financial covenant requirements. Except in the case of a default, which would make the borrowings under the Amended and Restated Credit Agreement fully callable, amounts borrowed under the Amended and Restated Credit Agreement will not mature prior to the May 1, 2019 maturity date. Further, our cost of borrowing under the Amended and Restated Credit Agreement is determined by a ratings-based pricing grid. In the first quarter of 2015, our credit rating was lowered below investment grade. As a result of this ratings action, interest rates under the Amended and Restated Credit Agreement increased. As of March 31, 2015, there was no outstanding balance on the revolving credit facility under the Amended and Restated Credit Agreement. We had unused revolver capacity of $1,249 million, net of letters of credit, under the Amended and Restated Credit Agreement, of which $1,205 million was available for general working capital purposes. As of May 1, 2015, we had $9 million of credit facility borrowings outstanding and had approximately $1,240 million of unused capacity under the Amended and Restated Credit Agreement.

Our commercial paper program previously served as an alternative source of funding, and did not increase our overall borrowing capacity. The lowering of our credit rating below investment grade in the first quarter of 2015 has eliminated our ability to utilize our commercial paper program.

In March 2014, we issued $325 million of 2.70% five-year Senior Notes due April 1, 2019 and $400 million of 5.60% 30-year Senior Notes due April 1, 2044. We received proceeds of $320 million, and $392 million, net of underwriters' fees, related expenses and unamortized discounts which we used to pay a portion of the consideration for the contribution and acquisition of: (i) a 33.33% interest in each of the Sand Hills and Southern Hills pipeline entities; (ii) the remaining 20% interest in the Eagle Ford system; (iii) the Lucerne 1 plant; and (iv) the Lucerne 2 plant, or the March 2014 Transactions. Interest on the notes is paid semi-annually on April 1 and October 1 of each year, commencing October 1, 2014. The notes will mature on April 1, 2019 and April 1, 2044, unless redeemed prior to maturity.

In April 2015, we filed a new universal shelf registration statement with the SEC, that became effective upon filing, in order to replace an existing shelf registration statement that was set to expire. As with the expiring shelf registration statement, the new universal shelf registration statement also allows us to issue an unlimited amount of common units and debt securities. We have issued no common units or debt securities under this registration statement.

During the three months ended March 31, 2015, we issued 788,033 common units pursuant to our 2014 equity distribution agreement and received proceeds of $31 million, net of commissions and accrued offering costs of less than $1 million, which were used to finance growth opportunities and for general partnership purposes. As of March 31, 2015, approximately $349 million remained available for sale pursuant to the 2014 equity distribution agreement.

In March 2014, we issued 14,375,000 common units to the public at $48.90 per unit. We received proceeds of $677 million, net of offering costs.

In March 2014, we issued 4,497,158 common units to DCP Midstream, LLC as partial consideration for the March 2014 Transactions.

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing activities through 2017 with fixed price commodity swaps, with the majority of our positions settling through the first quarter of 2016. For additional information regarding our derivative activities, please read Item 3. "Quantitative and Qualitative Disclosures about Market Risk" contained herein.

The counterparties to the majority of our commodity swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty's assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis.

Working Capital — Working capital is the amount by which current assets exceed current liabilities. Current assets are reduced by our quarterly distributions, which are required under the terms of our partnership agreement based on Available Cash, as defined in the partnership agreement. In general, our working capital is impacted by changes in the prices of commodities that we buy and sell, inventory levels, and other business factors that affect our net income and cash flows. Our working capital is also impacted by the timing of operating cash receipts and disbursements, borrowings of and payments on debt, capital expenditures, and increases or decreases in other long-term assets.

We had working capital deficits of $55 million and $11 million as of March 31, 2015 and December 31, 2014, respectively. The change in working capital is primarily attributable to current maturities of our long-term debt of $250 million, net derivative working capital of $163 million as of March 31, 2015 as compared to $187 million as of December 31, 2014, and the factors described above. We expect that our future working capital requirements will be impacted by these same factors.

As of March 31, 2015, we had $33 million in cash and cash equivalents. Of this balance, $1 million was held by consolidated subsidiaries we do not wholly own. Other than the cash held by these subsidiaries, this cash balance was available for general partnership purposes.

Cash Flow — Operating, investing and financing activities were as follows:

	Three Months Ended March 31,	
	2015	2014
	(Millions)	
Net cash provided by operating activities	$188	$146
Net cash used in investing activities	$(90)	$(896)
Net cash (used in) provided by financing activities	$(90)	$765

Three Months Ended March 31, 2015 vs. Three Months Ended March 31, 2014

Operating Activities — Net cash provided by operating activities increased $42 million in 2015 compared to 2014 primarily as a result of the following:

•$39 million increase in cash attributable to the timing of cash receipts and disbursements related to operations, including the receipt of $61 million for our net hedge cash settlements for the three months ended March 31, 2015; and

•$13 million increase in cash distributions from unconsolidated affiliates primarily due to increased earnings. Distributions exceeded earnings by $3 million for the three months ended March 31, 2015. For additional information regarding fluctuations in our earnings from unconsolidated affiliates, please read "Results of Operations".

These increases were partially offset by:

•$10 million decrease in cash attributable to lower income, after adjusting our $20 million decrease in net income for non-cash items.

Investing Activities — Net cash used in investing activities decreased $806 million in 2015 compared to 2014 primarily as a result of the following:

•$769 million decrease related to the March 2014 Transactions; and

•$40 million decrease in cash contributions to our unconsolidated affiliates. In 2014, we primarily made contributions to the Keathley Canyon project at Discovery, which was placed into service in the first quarter of 2015, and Front Range, which was placed into service in February 2014. In 2015, we made contributions to the expansion projects at our Sand Hills pipeline.

These decreases were partially offset by:

•$2 million increase in capital expenditures; and

•$1 million decrease in cash inflows attributable to cash received from the sale of assets in the first quarter of 2014.

Financing Activities — Net cash used in financing activities was $90 million for the three months ended March 31, 2015 as compared to net cash provided by financing activities of $765 million for the three months ended March 31, 2014 primarily as a result of the following:

•$646 million decrease in proceeds from the issuance of common units to the public. We issued approximately 1 million common units to the public in the first quarter of 2015 as compared to approximately 14 million units in the first quarter of 2014;

•$405 million decrease in net debt borrowings; and

•$34 million increase in cash distributions to our limited and general partners primarily attributable to units issued during 2014 and an increase in our quarterly distribution rate over the rate paid for the first quarter of 2014.

These events were partially offset by:

•$218 million in cash outflows in the first quarter of 2014 related to our March 2014 Transactions;

•$6 million decrease in deferred financing costs attributable to our debt issuance associated with the March 2014 Transactions; and

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•$6 million decrease in net distributions to noncontrolling interests primarily due to our acquisition of the remaining 20% interest in the Eagle Ford system in 2014.

Three Months Ended March 31, 2014

Net Cash Provided by Operating Activities — We paid $2 million for our net hedge cash settlements for the three months ended March 31, 2014. We received cash distributions from unconsolidated affiliates of $13 million during the three months ended March 31, 2014. Distributions exceeded earnings by $10 million for the three months ended March 31, 2014.

Net Cash Used in Investing Activities — Net cash used in investing activities during the three months ended March 31, 2014 was comprised of: (1) the acquisition of unconsolidated affiliates of $669 million related to the contribution of 33.33% interests in each of the Sand Hills and Southern Hills pipelines; (2) acquisitions of $100 million related to our acquisition of the Lucerne 1 and Lucerne 2 plants; (3) investments in unconsolidated affiliates of $65 million consisting of $42 million to Discovery, $21 million to Front Range and $2 million to Texas Express; and (4) capital expenditures of $63 million (our portion of which was $58 million and the noncontrolling interests portion was $5 million) consisting of construction of the Goliad plant, expansion of the O'Connor plant, expansion of our Chesapeake facility and other projects; partially offset by (1) other activity of $1 million.

Net Cash Provided by Financing Activities — Net cash provided by financing activities during the three months ended March 31, 2014 was comprised of: (1) proceeds from long-term debt of $719 million, (2) proceeds from the issuance of common units, net of offering costs, of $677 million; (3) contributions from noncontrolling interests of $3 million; partially offset by (4) net commercial paper activity of $314 million; (5) purchase of additional interest in a subsidiary of $198 million; (6) distributions to our limited partners and general partner of $86 million; (7) excess purchase price over acquired interests of $14 million; (8) distributions to noncontrolling interests of $10 million; (9) payment of deferred financing costs of $6 million; and (10) net change in advances to predecessor from DCP Midstream, LLC of $6 million.

As of March 31, 2014, we had unused capacity under the revolving credit facility of $978 million, all of which was available for general working capital purposes.

We expect to continue to use cash provided by operating activities for the payment of distributions to our unitholders and general partner. See Note 11. "Partnership Equity and Distributions" in the Notes to Condensed Consolidated Financial Statements in Item 1. “Financial Statements.”

Capital Requirements — The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to consist of the following:

- maintenance capital expenditures, which are cash expenditures to maintain our cash flows, operating or earnings capacity. These expenditures add on to or improve capital assets owned, including certain system integrity, compliance and safety improvements. Maintenance capital expenditures also include certain well connects, and may include the acquisition or construction of new capital assets; and
- expansion capital expenditures, which are cash expenditures to increase our cash flows, operating or earnings capacity. Expansion capital expenditures include acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines and well connects, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets).

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. We anticipate maintenance capital expenditures of between $50 million and $60 million, and approved expenditures for expansion capital of approximately $300 million, for the year ending December 31, 2015. Expansion capital expenditures include construction of the Lucerne 2 plant, the Grand Parkway gathering project and expansion of the Panola pipeline, which will be shown as an investment in unconsolidated affiliates in our condensed consolidated statements of cash flows. The board of directors of our General Partner may, at its discretion, approve additional growth and maintenance capital during the year.

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The following table summarizes our maintenance and expansion capital expenditures for our consolidated entities:

	Three Months Ended March 31, 2015			Three Months Ended March 31, 2014		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(Millions)					
Our portion	$7	$58	$65	$6	$52	$58
Noncontrolling interest portion and reimbursable projects (a)	—	—	—	1	4	5
Total	$7	$58	$65	$7	$56	$63

(a) Represents the noncontrolling interest and reimbursable portion of our capital expenditures. We have entered into agreements with third parties whereby we will be reimbursed for certain expenditures. Depending on the timing of these payments, we may be reimbursed prior to incurring the capital expenditure.

In addition, we invested cash in unconsolidated affiliates of $25 million and $65 million during the three months ended March 31, 2015 and 2014, respectively, to fund our share of capital expansion projects.

We intend to make cash distributions to our unitholders and our general partner. Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, which will include debt and common unit issuances, to fund our acquisition and capital expenditures.

We expect to fund future capital expenditures with funds generated from our operations, borrowings under our Amended and Restated Credit Agreement, the issuance of additional partnership units and the issuance of long-term debt. If these sources are not sufficient, we will reduce our discretionary spending.

Cash Distributions to Unitholders — Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all Available Cash, as defined in the partnership agreement. We made cash distributions to our unitholders and general partner of $120 million and $86 million during the three months ended March 31, 2015 and 2014, respectively. We intend to continue making quarterly distribution payments to our unitholders and general partner to the extent we have sufficient cash from operations after the establishment of reserves.

Total Contractual Cash Obligations and Off-Balance Sheet Obligations

A summary of our total contractual cash obligations as of March 31, 2015, is as follows:

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
	(Millions)				
Debt (a)	$3,356	$339	$661	$456	$1,900
Operating lease obligations (b)	86	16	27	19	24
Purchase obligations (c)	136	129	3	1	3
Other long-term liabilities (d)	35	—	1	—	34
Total	$3,613	$484	$692	$476	$1,961

(a) Includes interest payments on debt securities that have been issued. These interest payments are $89 million, $161 million, $131 million, and $650 million for less than one year, one to three years, three to five years, and thereafter, respectively.

(b) Our operating lease obligations are contractual obligations and include railcar leases, which provide supply and storage infrastructure for our Wholesale Propane Logistics business, and natural gas storage in our Northern Louisiana system and a firm transportation commitment within our Natural Gas Services business. The natural gas storage arrangement enables us to maximize the value between the current price of natural gas and the future market price of natural gas.

(c) Our purchase obligations are contractual obligations and include purchase orders and non-cancelable construction agreements for capital expenditures, various non-cancelable commitments to purchase physical quantities of propane supply for our Wholesale Propane Logistics business and other items. For contracts where the price paid is based on an index or other market-based rates, the amount is based on the forward market prices or current market rates as of March 31, 2015. Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized in the condensed consolidated balance sheets. Purchase obligations also exclude current and long-term unrealized losses on derivative instruments included in the condensed consolidated balance sheet, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts may be settled financially at the difference between the future market price and the contractual price and may result in cash payments or cash receipts in the future, but generally do not require delivery of physical quantities of the underlying commodity. In addition, many of our gas purchase contracts include short and long-term commitments to purchase produced gas at market prices. These contracts, which have no minimum quantities, are excluded from the table.

(d) Other long-term liabilities include $28 million of asset retirement obligations of which an insignificant amount may be settled within the next five years, $4 million of gas purchase liability, $2 million of right of way liability and $1 million of environmental reserves recognized in the March 31, 2015 condensed consolidated balance sheet. In addition, $13 million of deferred state income taxes were excluded from the table above as the amount and timing of any payments are not subject to reasonable estimation.

We have no items that are classified as off balance sheet obligations.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

For an in-depth discussion of our market risks, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" in our Annual Report on Form 10-K for the year ended December 31, 2014.

The following tables set forth additional information about our fixed price swaps used to mitigate a portion of our natural gas and NGL price risk associated with our percent-of-proceeds arrangements and our condensate price risk associated with our gathering operations. As noted in the table below, the majority of our positions extend through 2015 with a limited amount settling in 2016 and 2017. Our positions as of May 1, 2015 are as follows:

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions		Reference Price	Price Range
April 2015 — December 2015	Natural Gas	(24,738) MMBtu/d		IFERC Monthly Index Price for Houston Ship Channel (c)	$4.50/MMBtu
January 2016 — March 2016	Natural Gas	(16,163) MMBtu/d		IFERC Monthly Index Price for Houston Ship Channel (c)	$4.50/MMBtu
April 2015 — December 2015	Natural Gas	(8,677) MMBtu/d		IFERC Monthly Index Price for Henry Hub (d)	$4.50/MMBtu
January 2016 — March 2016	Natural Gas	(4,041) MMBtu/d		IFERC Monthly Index Price for Henry Hub (d)	$4.50/MMBtu
January 2016 — December 2016	Natural Gas	(5,000) MMBtu/d	(f)	NYMEX Final Settlement Price (e)	$4.18/MMBtu
January 2017 — December 2017	Natural Gas	(17,500) MMBtu/d	(f)	NYMEX Final Settlement Price (e)	$4.17 - $4.27/MMBtu
April 2015 — December 2015	NGLs	(15,168) Bbls/d		Mt.Belvieu Non-TET (b)	$0.64 - $1.89/Gal
	NGLs	(8,937) Bbls/d		Mt.Belvieu Non-TET (b)	$0.64 - $1.89/Gal

January 2016 — March 2016				
April 2015 — December 2015	Crude Oil	(2,043) Bbls/d	Asian-pricing of NYMEX crude oil futures (a)	\$87.60 - \$100.04/Bbl
January 2016 — March 2016	Crude Oil	(1,642) Bbls/d	Asian-pricing of NYMEX crude oil futures (a)	\$85.15 - \$101.30/Bbl
April 2016 — December 2016	Crude Oil	(1,500) Bbls/d	Asian-pricing of NYMEX crude oil futures (a)	\$85.15 - \$101.30/Bbl
January 2015 — December 2015	Natural Gas	7,500 MMBtu/d	NYMEX Final Settlement Price (e)	\$4.15 - \$4.22/MMBtu

(a) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).
(b) The average monthly OPIS price for Mt. Belvieu Non-TET.
(c) The Inside FERC monthly published index price for Houston Ship Channel.
(d) The Inside FERC monthly published index price for Henry Hub.
(e) NYMEX final settlement price for natural gas futures contracts (NG).
(f) Represents a position in which the counterparty is DCP Midstream, LLC.

Our sensitivities for 2015 as shown in the table below are estimated based on our average estimated commodity price exposure and commodity cash flow protection activities for the calendar year 2015, and exclude the impact from non-cash mark-to-market on our commodity derivatives. We utilize direct product crude oil, natural gas and NGL derivatives to mitigate a portion of our condensate, natural gas and NGL commodity price exposure. These sensitivities are associated with our unhedged condensate, natural gas and NGL volumes.

Commodity Sensitivities Excluding Non-Cash Mark-To Market

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income Attributable to Partners (Millions)
Natural gas prices	$0.10	MMBtu	$0.3
Crude oil prices	$1.00	Barrel	$0.1
NGL prices	$0.01	Gallon	$0.8

In addition to the linear relationships in our commodity sensitivities above, additional factors cause us to be less sensitive to commodity price declines. A portion of our net income is derived from fee-based contracts and a portion from percentage of liquids processing arrangements that contain minimum fee clauses in which our processing margins convert to fee-based arrangements as NGL prices decline.

The above sensitivities exclude the impact from arrangements where producers on a monthly basis may elect to not process their natural gas in which case we retain a portion of the customers' natural gas in lieu of NGLs as a fee. The above sensitivities also exclude certain related processing arrangements where we control the processing or by-pass of the production based upon individual economic processing conditions. Under each of these types of arrangements, our processing of the natural gas would yield favorable processing margins. Less than 10% of our gas throughput is associated with these arrangements.

We estimate the following non-cash sensitivities for 2015 related to the mark-to-market on our commodity derivatives associated with our commodity cash flow protection activities:

Non-Cash Mark-To-Market Commodity Sensitivities

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income Attributable to Partners) (Millions)
Natural gas prices	$0.10	MMBtu	$2
Crude oil prices	$1.00	Barrel	$1
NGL prices	$0.01	Gallon	$2

While the above commodity price sensitivities are indicative of the impact that changes in commodity prices may have on our annualized net income, changes during certain periods of extreme price volatility and market conditions or changes in the relationship of the price of NGLs and crude oil may cause our commodity price sensitivities to vary significantly from these estimates.

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally related to the price of crude oil. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long-term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital for producers to increase natural gas exploration and production. To minimize potential future commodity-based pricing and cash flow volatility, we have entered into a series of derivative financial instruments. As a result of these transactions, we have mitigated a portion of our expected commodity price risk relating to the equity volumes associated with our gathering and processing activities through 2017, with the majority of our positions settling through the first quarter of 2016.

Based on historical trends, we generally expect NGL prices to directionally follow changes in crude oil prices over the long-term. However, the pricing relationship between NGLs and crude oil may vary, as we believe crude oil prices will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy, whereas NGL prices are more correlated to supply and U.S. petrochemical demand. However, the level of NGL exports has increased in recent years. We believe that future natural gas prices will be influenced by North American supply deliverability, the severity of winter and summer weather, the level of North American production and drilling activity of exploration and production companies and the balance of trade between imports and exports of liquid natural gas and NGLs. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also reduce North American drilling activity. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would reduce natural gas volumes gathered and processed, but could increase commodity prices, if supply were to fall relative to demand levels.
Natural Gas Storage and Pipeline Asset Based Commodity Derivative Program — Our natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.
A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period condensed consolidated statements of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our condensed consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

The following tables set forth additional information about our derivative instruments used to mitigate a portion of our natural gas price risk associated with our Southeast Texas storage operations, as of March 31, 2015:
Inventory

Period ended	Commodity	Notional Volume - Long Positions	Fair Value (millions)	Weighted Average Price
March 31, 2015	Natural Gas	7,891,510 MMBtu	$21	$2.61/MMBtu

Commodity Swaps

Period	Commodity	Notional Volume -(Short)/Long Positions	Fair Value (millions)	Price Range
April 2015-January 2016	Natural Gas	(58,252,500) MMBtu	$32	$2.62 - $4.23/MMBtu
April 2015-January 2016	Natural Gas	50,962,500 MMBtu	$(29)	$2.59 - $4.21/MMBtu

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the SEC under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the Commission’s rules and forms, and that information is accumulated and communicated to the management of our general partner, including our general partner’s principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. The management of our general partner evaluated, with the participation of the Certifying Officers, the effectiveness of our disclosure controls and procedures as of March 31, 2015, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of March 31, 2015, our disclosure controls and procedures were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There were no changes in internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the first quarter of 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION
Item 1. Legal Proceedings

The information required for this item is provided in “Commitments and Contingent Liabilities,” included in Note 17 in Item 8 of our Annual Report on Form 10-K for the year ended December 31, 2014 and Note 13 in Item 1 of this Quarterly Report on Form 10-Q.

Item 1A. Risk Factors

In addition to the other information set forth in this report, careful consideration should be given to the risk factors discussed in Part I, “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2014. An investment in our securities involves various risks. When considering an investment in us, you should consider carefully all of the risk factors described below and in our Annual Report on Form 10-K for the year ended December 31, 2014.

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, under our partnership agreement, the owners of our general partner may pledge, impose a lien or transfer all or a portion of their respective ownership interest in our general partner to a third party. On March 23, 2015, we were advised by DCP Midstream, LLC, the owner of our general partner, that DCP Midstream, LLC pledged its limited partner and general partner interests in us as collateral under its credit agreement with various financial institutions. If DCP Midstream, LLC defaults on its obligations under its credit agreement, its lenders may foreclose on such pledged limited partner and general partner interests. Any new owners of our general partner would then be in a position to replace the board of directors and officers of the general partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

Item 6. Exhibits

Exhibit Number		Description
3.1	*	Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005, as amended by Amendment No. 1 dated January 20, 2009 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
3.2	*	Amendment No. 2 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated February 14, 2013 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 21, 2013).
3.3	*	Amendment No. 3 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated November 6, 2013 (attached as Exhibit 3.3 to DCP Midstream Partners, LP's Quarterly Report on Form 10-Q (File No. 001-32678) filed with the SEC on November 6, 2013).
3.4	*	First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP dated December 7, 2005 (attached as Exhibit 3.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
3.5	*	Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated November 1, 2006 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006).
3.6	*	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated April 11, 2008 (attached as Exhibit 4.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 14, 2008).
3.7	*	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated April 1, 2009 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009).
10.1	*	Third Amendment to Services Agreement, dated February 23, 2015, by and between DCP Midstream Partners, LP and DCP Midstream, LP (attached as Exhibit 10.15 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 25, 2015).
12.1		Computation of Ratio of Earnings to Fixed Charges.
31.1		Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2		Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1		Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2		Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101		Financial statements from the Quarterly Report on Form 10-Q of DCP Midstream Partners, LP for the three months ended March 31, 2015, formatted in XBRL: (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Comprehensive Income, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Consolidated Statements of Changes in Equity, and (vi) the Notes to the Condensed Consolidated Financial Statements.

* Such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on May 7, 2015.

DCP Midstream Partners, LP

By:	DCP Midstream GP, LP its General Partner	
By:	DCP Midstream GP, LLC its General Partner	
By:	/s/ Wouter T. van Kempen	
	Name:	Wouter T. van Kempen
	Title:	Chief Executive Officer (Principal Executive Officer)
By:	/s/ Sean P. O'Brien	
	Name:	Sean P. O'Brien
	Title:	Group Vice President and Chief Financial Officer (Principal Financial Officer)

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