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

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2017
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, LP
(Exact name of registrant as specified in its charter)

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

Registrant's telephone number, including area code: (303) 595-3331

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

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

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

Large accelerated filer	☒		Accelerated filer	☐	Emerging growth company	☐
Non-accelerated filer	☐	(Do not check if a smaller reporting company)	Smaller reporting company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a)
of the Exchange Act. ☐

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

As of November 2, 2017, there were 143,309,828 common units representing limited partner interests outstanding.

DCP MIDSTREAM, LP
FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2017

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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,” “estimate,” “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 "Managements Discussion and Analysis of Financial Condition and Results of Operations - Factors That May Significantly Affect Our Results" included as Exhibit 99.3 in our Current Report on Form 8-K filed with the Securities and Exchange Commission or the SEC, on May 25, 2017 (the "May 2017 8-K"), 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, 2016 filed with the SEC on February 15, 2017, 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;
- volatility in the price of our common units;
- general economic, market and business conditions;
- our ability to continue the safe and reliable operation of our assets;
- 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;
- 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 credit agreement and the indentures governing our notes, as well as our ability to maintain our credit ratings;
- the creditworthiness of our customers and the counterparties to our transactions;
- the amount of collateral we may be required to post from time to time in our transactions;
- industry changes, including the impact of bankruptcies, consolidations, alternative energy sources, technological advances and changes in competition;
- our ability to grow through organic growth projects, or acquisitions, and the successful integration and future performance of such assets;
- our ability to hire, train, and retain qualified personnel and key management to execute our business strategy;
- 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;
- 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; and
- the amount of natural gas we gather, compress, treat, process, transport, store and sell, or the NGLs we produce, fractionate, transport, store and sell, 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 natural gas or NGLs.

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, except as required by applicable securities laws.

Item 1. ***Financial Statements***

DCP MIDSTREAM, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2017	December 31, 2016
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 312	$ 1
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $7 and $4 million, respectively	690	652
Affiliates	138	134
Other	18	6
Inventories	62	72
Unrealized gains on derivative instruments	32	42
Collateral cash deposits	42	71
Other	17	16
Total current assets	1,311	994
Property, plant and equipment, net	8,926	9,069
Goodwill	231	236
Intangible assets, net	109	137
Investments in unconsolidated affiliates	3,002	2,969
Unrealized gains on derivative instruments	4	5
Other long-term assets	188	201
Total assets	$ 13,771	$ 13,611
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 845	$ 677
Affiliates	57	48
Other	17	10
Current maturities of long-term debt	500	500
Unrealized losses on derivative instruments	42	91
Accrued interest	69	72
Accrued taxes	88	49
Accrued wages and benefits	43	72
Capital spending accrual	17	20
Other	106	84
Total current liabilities	1,784	1,623
Long-term debt	4,711	4,907
Unrealized losses on derivative instruments	10	1
Deferred income taxes	30	28
Other long-term liabilities	193	199
Total liabilities	6,728	6,758
Commitments and contingent liabilities		
Equity:		
Predecessor equity	—	4,220
Limited partners (143,309,828 and 114,749,848 common units issued and outstanding, respectively)	6,870	2,591
General partner	155	18
Accumulated other comprehensive loss	(9)	(8)
Total partners’ equity	7,016	6,821
Noncontrolling interests	27	32
Total equity	7,043	6,853
Total liabilities and equity	$ 13,771	$ 13,611

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, NGLs and condensate	$ 1,618	$ 1,397	$ 4,756	$ 3,769
Sales of natural gas, NGLs and condensate to affiliates	318	249	885	662
Transportation, processing and other	162	162	474	469
Trading and marketing (losses) gains, net	(43)	15	10	10
Total operating revenues	2,055	1,823	6,125	4,910
Operating costs and expenses:				
Purchases of natural gas and NGLs	1,550	1,311	4,528	3,510
Purchases of natural gas and NGLs from affiliates	145	126	411	356
Operating and maintenance expense	168	161	513	506
Depreciation and amortization expense	94	94	282	284
General and administrative expense	69	64	202	187
Asset impairments	48	—	48	—
Other expense (income), net	—	14	15	(68)
Gain on sale of assets, net	—	(41)	(34)	(35)
Restructuring costs	—	2	—	10
Total operating costs and expenses	2,074	1,731	5,965	4,750
Operating (loss) income	(19)	92	160	160
Earnings from unconsolidated affiliates	74	75	234	214
Interest expense, net	(73)	(77)	(219)	(235)
(Loss) income before income taxes	(18)	90	175	139
Income tax expense	(2)	(1)	(5)	(6)
Net (loss) income	(20)	89	170	133
Net income attributable to noncontrolling interests	—	—	(1)	(1)
Net (loss) income attributable to partners	(20)	89	169	132
Net loss attributable to predecessor operations	—	31	—	105
General partner’s interest in net income	(39)	(31)	(122)	(93)
Net (loss) income allocable to limited partners	$ (59)	$ 89	$ 47	$ 144
Net (loss) income per limited partner unit — basic and diluted	$ (0.41)	$ 0.78	$ 0.33	$ 1.26
Weighted-average limited partner units outstanding — basic and diluted	143.3	114.7	143.3	114.7

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Millions)			
Net (loss) income	$ (20)	$ 89	$ 170	$ 133
Other comprehensive income:				
Reclassification of cash flow hedge losses into earnings	—	—	1	—
Total other comprehensive income	—	—	1	—
Total comprehensive (loss) income	(20)	89	171	133
Total comprehensive income attributable to noncontrolling interests	—	—	(1)	(1)
Total comprehensive (loss) income attributable to partners	$ (20)	$ 89	$ 170	$ 132

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30,	
	2017	2016
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$ 170	$ 133
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	282	284
Earnings from unconsolidated affiliates	(234)	(214)
Distributions from unconsolidated affiliates	270	274
Net unrealized (gains) losses on derivative instruments	(1)	80
Gain on sale of assets, net	(34)	(35)
Asset impairments	48	—
Deferred income tax, net	—	3
Other, net	29	28
Change in operating assets and liabilities, which provided (used) cash, net of effects of acquisitions:		
Accounts receivable	(59)	(137)
Inventories	10	1
Accounts payable	179	63
Accrued interest	(4)	(15)
Other current assets and liabilities	19	38
Other long-term assets and liabilities	9	18
Net cash provided by operating activities	684	521
INVESTING ACTIVITIES:		
Capital expenditures	(258)	(113)
Investments in unconsolidated affiliates, net	(70)	(38)
Proceeds from sale of assets	130	160
Net cash (used in) provided by investing activities	(198)	9
FINANCING ACTIVITIES:		
Proceeds from long-term debt	—	2,926
Payments of long-term debt	(195)	(3,216)
Net change in advances to predecessor from DCP Midstream, LLC	418	150
Distributions to limited partners and general partner	(390)	(362)
Distributions to noncontrolling interests	(6)	(6)
Other	(2)	(10)
Net cash used in financing activities	(175)	(518)
Net change in cash and cash equivalents	311	12
Cash and cash equivalents, beginning of period	1	3
Cash and cash equivalents, end of period	$ 312	$ 15

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM, 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, 2017	$ 4,220	$ 2,591	$ 18	$ (8)	$ 32	$ 6,853
Net income	—	47	122	—	1	170
Other comprehensive income	—	—	—	1	—	1
Net change in parent advances	—	418	—	—	—	418
Acquisition of the DCP Midstream Business	(4,220)	—	—	—	—	(4,220)
Deficit purchase price under carrying value of the Transaction	—	3,094	—	(2)	—	3,092
Issuance of 28,552,480 common units and 2,550,644 general partner units to DCP Midstream, LLC and affiliates	—	1,033	92	—	—	1,125
Distributions to limited partners and general partner	—	(313)	(77)	—	—	(390)
Distributions to noncontrolling interests	—	—	—	—	(6)	(6)
Balance, September 30, 2017	$ —	$ 6,870	$ 155	$ (9)	$ 27	$ 7,043

See accompanying notes to condensed consolidated financial statements.

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

	Partners' Equity					
	Predecessor Equity	Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Equity
	(Millions)					
Balance, January 1, 2016	$ 4,287	$ 2,762	$ 18	$ (8)	$ 33	$ 7,092
Net (loss) income	(105)	144	93	—	1	133
Net change in parent advances	150	—	—	—	—	150
Distributions to limited partners and general partner	—	(269)	(93)	—	—	(362)
Distributions to noncontrolling interests	—	—	—	—	(6)	(6)
Balance, September 30, 2016	$ 4,332	$ 2,637	$ 18	$ (8)	$ 28	$ 7,007

See accompanying notes to condensed consolidated financial statements.

1. Description of Business and Basis of Presentation

DCP Midstream, LP, with its consolidated subsidiaries, or "us", "we", "our" or the "Partnership" is a Delaware limited partnership formed in 2005 by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets.

Our Partnership includes our Gathering and Processing and Logistics and Marketing segments. For additional information regarding these segments, see Note 16 - 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 Enbridge, Inc and its affiliates, or Enbridge. Spectra Energy Corp owned 50% of DCP Midstream, LLC prior to the completion of its merger with Enbridge in the first quarter of 2017. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. As of September 30, 2017, DCP Midstream, LLC owned approximately 38.1% of us, including limited partner and general partner interests.

On December 30, 2016, we entered into a Contribution Agreement (the “Contribution Agreement”) with DCP Midstream, LLC and DCP Midstream Operating, LP (the “Operating Partnership”), a 100% owned subsidiary of the Partnership, which closed effective January 1, 2017. The transactions and documents contemplated by the Contribution Agreement are collectively referred to hereafter as the “Transaction.” Our predecessor results consist of all of the ownership interests of DCP Midstream, LLC in all of its subsidiaries that owned operating assets ("The DCP Midstream Business"), which we acquired from DCP Midstream, LLC on January 1, 2017. 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 were retrospectively adjusted to furnish comparative information, similar to the pooling method. Accordingly, our condensed consolidated financial statements include the historical results of The DCP Midstream Business for all periods presented. For additional information regarding the Transaction, see Note 3 - Acquisitions.

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.

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 in consolidation.

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 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 presented not misleading. Results of operations for the three and nine months ended September 30, 2017 are not necessarily indicative of the results that may be expected for the year ending December 31, 2017. 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 2016 audited consolidated financial statements and notes thereto included as Exhibit 99.4 in the May 2017 8-K.

2. New Accounting Pronouncements

Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2016-15 "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments," or ASU 2016-15 - In August 2016, the FASB issued ASU 2016-15, which amends certain cash flow statement classification guidance. We intend to adopt this ASU for interim and annual reporting periods beginning after December 15, 2017. The adoption of this ASU will have no impact on our condensed consolidated cash flows.

FASB ASU, 2016-02 "Leases (Topic 842)," or ASU 2016-02 - In February 2016, the FASB issued ASU 2016-02, which requires lessees to recognize a lease liability on a discounted basis and the right of use of a specified asset at the commencement date for all leases. This ASU is effective for interim and annual reporting periods beginning after December 15, 2018, with the option to early adopt for financial statements that have not been issued. We are currently evaluating the potential impact this standard will have on our condensed consolidated financial statements and related disclosures.

FASB ASU *2014-09 "Revenue from Contracts with Customers (Topic 606)," or ASU 2014-09 and related interpretations and amendments* - In May 2014, the FASB issued ASU 2014-09, which supersedes the revenue recognition requirements of Accounting Standards Codification Topic 605 "Revenue Recognition." This ASU is effective for annual reporting periods beginning after December 15, 2017, with the option to adopt as early as annual reporting periods beginning after December 15, 2016. We plan to adopt this ASU using the modified retrospective method. The initial cumulative effect will be recognized at the date of adoption. Our evaluation of ASU 2014-09 is ongoing and not complete. The FASB has issued and may issue in the future, interpretative guidance, which may cause our evaluation to change. Accordingly, at this time we cannot estimate the impact upon adoption.

3. Acquisitions

On January 1, 2017, DCP Midstream, LLC contributed to us: (i) its ownership interests in all of its subsidiaries owning operating assets, and (ii) $424 million of cash (together the "Contributions"). In consideration of the Partnership's receipt of the Contributions, (i) the Partnership issued 28,552,480 common units to DCP Midstream, LLC and 2,550,644 general partner units to the General Partner in a private placement and (ii) the Operating Partnership assumed $3,150 million of DCP Midstream, LLC's debt.

Pursuant to the Contribution Agreement, DCP Midstream, LLC agreed to cause the General Partner to enter into Amendment No. 3 (the "Third Amendment to the Partnership Agreement") to the Second Amended and Restated Agreement of Limited Partnership of the Partnership, dated November 1, 2006, as amended (the "Partnership Agreement"). The Third Amendment to the Partnership Agreement includes terms that amend the Partnership Agreement to cause the incentive distributions payable to the holders of the Partnership's incentive distribution rights with respect to the fiscal years 2017, 2018 and 2019 to, in certain circumstances, be reduced in an amount up to $100 million per fiscal year as necessary to provide that the distributable cash flow of the Partnership (as adjusted) during such year meets or exceeds the amount of distributions made by the Partnership (as adjusted) to the partners of the Partnership with respect to such year.

4. Dispositions

In June 2017, we closed a transaction with Tallgrass Midstream, LLC to sell our 100% interest in our Douglas gathering system, which primarily consisted of approximately 1,500 miles of gathering lines within our Gathering and Processing segment, for approximately $129 million, subject to customary purchase price adjustments. We recognized a gain of approximately $34 million, net of goodwill allocation, in the second quarter of 2017.

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Services Agreement and Other General and Administrative Charges

Pursuant to the Contribution Agreement, on January 1, 2017, the Partnership entered into the Services and Employee Secondment Agreement (the “Services Agreement”), which replaced the services agreement between the Partnership and DCP Midstream, LLC, dated February 14, 2013, as amended. Under the Services Agreement, we are required to reimburse DCP Midstream, LLC for costs, expenses, and expenditures incurred or payments made on our behalf for general and administrative functions including, but not limited to, legal, accounting, compliance, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, benefit plan maintenance and administration, credit, payroll, internal audit, taxes and engineering, as well as salaries and benefits of seconded employees, insurance coverage and claims, capital expenditures, maintenance and repair costs and taxes. There is no limit on the reimbursements we make to DCP Midstream, LLC under the Services Agreement for costs, expenses and expenditures incurred or payments made on our behalf. The following table summarizes employee related costs that were charged by DCP Midstream, LLC to the Partnership that are included in the condensed consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Millions)			
Employee related costs charged by DCP Midstream, LLC				
Operating and maintenance expense	$ 50	$ 51	$ 149	$ 158
General and administrative expense (including restructuring charges)	$ 46	$ 47	$ 116	$ 142

Phillips 66 and its Affiliates

We sell a portion of our residue gas and NGLs to Phillips 66 and Chevron Phillips Chemical LLC, or CPChem. In addition, we purchase NGLs from CPChem. CPChem is owned 50% by Phillips 66, and is considered a related party. Approximately 22% of our NGL production was committed to Phillips 66 and CPChem as of September 30, 2017. The primary production commitment on certain contracts began a ratable wind down period in December 2014 and expires in January 2019. We anticipate continuing to purchase and sell commodities with Phillips 66 and CPChem in the ordinary course of business.

Enbridge and its Affiliates

We sell NGLs to and purchase NGLs from Enbridge and its affiliates. We anticipate continuing to sell commodities to and purchase commodities from Enbridge and its affiliates in the ordinary course of business.

Unconsolidated Affiliates

We have entered into 15-year transportation agreements, with Sand Hills Pipeline, LLC, or Sand Hills, Southern Hills Pipeline, LLC, or Southern Hills, Front Range Pipeline LLC, or Front Range, and Texas Express Pipeline LLC, or Texas Express. Under the terms of these 15-year agreements, which commenced at each of the pipelines’ respective in-service dates and expire between 2028 and 2029, we have committed to transport minimum throughput volumes at rates defined in each of the pipelines’ respective tariffs.

We also sell a portion of our residue gas and NGLs to, purchase natural gas and other NGL products from, and provide gathering and transportation services to other unconsolidated affiliates. We anticipate continuing to purchase and sell commodities and provide services to unconsolidated affiliates in the ordinary course of business.

Under the terms of the Sand Hills LLC Agreement and the Southern Hills LLC Agreement, or the Sand Hills and Southern Hills LLC Agreements, Sand Hills and Southern Hills are required to reimburse us for any direct costs or expenses (other than general and administration services) which we incur on behalf of Sand Hills and Southern Hills. Additionally, Sand Hills and Southern Hills each pay us an annual service fee of $5 million, for centralized corporate functions provided by us as operator of Sand Hills and Southern Hills, 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 service fee, there is no limit on the reimbursements Sand Hills and Southern Hills make to us under the Sand Hills and Southern Hills LLC Agreements for other expenses and expenditures which we incur on behalf of Sand Hills or Southern Hills.

Summary of Transactions with Affiliates

The following table summarizes our transactions with affiliates:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Millions)			
Phillips 66 (including its affiliates):				
Sales of natural gas, NGLs and condensate to affiliates	$ 289	$ 237	$ 814	$ 633
Purchases of natural gas and NGLs from affiliates	$ 7	$ 6	$ 22	$ 12
Operating and maintenance and general administrative expenses	$ —	$ 1	$ 1	$ 1
Enbridge (including its affiliates):				
Sales of natural gas, NGLs and condensate to affiliates	$ 14	$ —	$ 34	$ —
Purchases of natural gas and NGLs from affiliates	$ 12	$ 7	$ 31	$ 25
Operating and maintenance and general administrative expenses	$ 1	$ 1	$ 2	$ 3
Unconsolidated affiliates:				
Sales of natural gas, NGLs and condensate to affiliates	$ 15	$ 12	$ 37	$ 29
Transportation, storage and processing to affiliates	$ 1	$ —	$ 4	$ 3
Purchases of natural gas and NGLs from affiliates	$ 126	$ 113	$ 358	$ 319

We had balances with affiliates as follows:

	September 30, 2017	December 31, 2016
	(Millions)	
Phillips 66 (including its affiliates):		
Accounts receivable	$ 113	$ 115
Accounts payable	$ 4	$ 4
Other assets	$ 1	$ 2
Enbridge (including its affiliates):		
Accounts receivable	$ 7	$ 1
Accounts payable	$ 7	$ 3
Other assets	$ —	$ 1
Other liabilities	$ —	$ 1
Unconsolidated affiliates:		
Accounts receivable	$ 18	$ 18
Accounts payable	$ 46	$ 41
Other assets	$ 3	$ 5

6. Inventories

Inventories were as follows:

	September 30, 2017	December 31, 2016
	(Millions)	
Natural gas	$ 32	$ 28
NGLs	30	44
Total inventories	$ 62	$ 72

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 and NGLs in the condensed consolidated statements of operations. We recognized no lower of cost or market adjustments during the three months ended September 30, 2017 or September 30, 2016. We recognized no lower of cost or market adjustments during the nine months ended September 30, 2017 and $3 million during the nine months ended September 30, 2016.

7. Property, Plant and Equipment

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

	Depreciable Life	September 30, 2017	December 31, 2016
		(Millions)	
Gathering and transmission systems	20 — 50 Years	$ 8,447	$ 8,560
Processing, storage and terminal facilities	35 — 60 Years	5,107	5,134
Other	3 — 30 Years	539	502
Construction work in progress		288	171
Property, plant and equipment		14,381	14,367
Accumulated depreciation		(5,455)	(5,298)
Property, plant and equipment, net		$ 8,926	$ 9,069

Interest capitalized on construction projects was $2 million and less than $1 million for the three months ended September 30, 2017 and 2016, respectively, and $4 million and less than $1 million for the nine months ended September 30, 2017 and 2016, respectively.

Depreciation expense was $90 million and $91 million for the three months ended September 30, 2017 and 2016, respectively, and $272 million and $275 million for the nine months ended September 30, 2017 and 2016, respectively.

8. Goodwill

We performed our annual goodwill assessment during the third quarter of 2017 at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete financial information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. As a result of our assessment, we concluded that the fair value of goodwill substantially exceeded its carrying value in our North reporting unit, the only reporting unit allocated goodwill included within our Gathering and Processing reportable segment and in our Marysville reporting unit included within our Logistics and Marketing reportable segment. For our Wholesale Propane reporting unit, which is included in our Logistics and Marketing reportable segment, the fair value exceeded the carrying value (including approximately $37 million of allocated goodwill) by less than 10%. We concluded that the entire amount of goodwill disclosed on the condensed consolidated balance sheet is recoverable.

We primarily used a discounted cash flow analysis, supplemented by a market approach analysis, to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows, including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information (including forecasted volumes and commodity prices), as well as historical and other factors. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

We expect that the fair value of our Wholesale Propane reporting unit will continue to exceed carrying value so long as our estimate of future cash flows and the market valuation remain consistent with current levels. A continued period of volatile propane prices could result in further deterioration of market multiples, comparable sales transactions prices, weighted average costs of capital, and our cash flow estimates. Changes to any one or combination of these factors, would result in changes to the reporting unit fair values discussed above which could lead to future impairment charges. Such potential impairment could have a material effect on our results of operations.

The carrying amount of goodwill in each of our reportable segments was as follows:

	September 30, 2017 (Millions)		
	Gathering and Processing	Logistics and Marketing	Total
Balance, January 1, 2017	$ 164	$ 72	$ 236
Dispositions	(5)	—	(5)
Balance, September 30, 2017	$ 159	$ 72	$ 231

9. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage Ownership	Carrying Value as of September 30, 2017 (Millions)	Carrying Value as of December 31, 2016 (Millions)
DCP Sand Hills Pipeline, LLC	66.67%	$ 1,563	$ 1,507
Discovery Producer Services LLC	40.00%	376	385
DCP Southern Hills Pipeline, LLC	66.67%	741	754
Front Range Pipeline LLC	33.33%	165	165
Texas Express Pipeline LLC	10.00%	90	93
Panola Pipeline Company, LLC	15.00%	24	25
Mont Belvieu Enterprise Fractionator	12.50%	24	23
Mont Belvieu 1 Fractionator	20.00%	13	10
Other	Various	6	7
Total investments in unconsolidated affiliates		$ 3,002	$ 2,969

Earnings from investments in unconsolidated affiliates were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Millions)			
DCP Sand Hills Pipeline, LLC	$ 37	$ 28	$ 105	$ 84
Discovery Producer Services LLC	14	20	59	52
DCP Southern Hills Pipeline, LLC	10	13	34	37
Front Range Pipeline LLC	5	5	12	14
Texas Express Pipeline LLC	4	2	7	6
Mont Belvieu Enterprise Fractionator	3	4	10	12
Mont Belvieu 1 Fractionator	2	2	6	7
Other	(1)	1	1	2
Total earnings from unconsolidated affiliates	$ 74	$ 75	$ 234	$ 214

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Millions)			
Statements of operations:				
Operating revenue	$ 358	$ 335	$ 1,063	$ 971
Operating expenses	$ 164	$ 136	$ 464	$ 390
Net income	$ 194	$ 199	$ 598	$ 576

	September 30, 2017	December 31, 2016
	(Millions)	
Balance sheets:		
Current assets	$ 242	$ 232
Long-term assets	5,253	5,274
Current liabilities	(165)	(156)
Long-term liabilities	(200)	(205)
Net assets	$ 5,130	$ 5,145

10. 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, 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 12 - Risk Management and Hedging Activities.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy and are categorized in their entirety in the same level of the fair value hierarchy as the lowest level input that is significant to the entire measurement. 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 exchange traded instruments (such as New York Mercantile Exchange, or NYMEX, crude oil or natural gas futures) or over-the-counter, or OTC, instruments (such as natural gas contracts, crude oil or NGL swaps). The exchange traded instruments are generally executed with a highly rated broker dealer serving as the clearinghouse for individual transactions.

Our activities expose us to varying degrees of commodity price risk. To mitigate a portion of this risk and to manage commodity price risk related primarily to owned natural gas storage and pipeline assets, we engage in natural gas asset based trading and marketing, and we may enter into natural gas and crude oil derivatives to lock in a specific margin when market conditions are favorable. A portion of this may be accomplished through the use of exchange traded derivative contracts. Such instruments are generally classified as Level 1 since the value is equal to the quoted market price of the exchange traded instrument as of our balance sheet date, and no adjustments are required. Depending upon market conditions and our strategy we may enter into exchange traded derivative positions with a significant time horizon to maturity. Although such instruments are exchange traded, market prices 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 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.

We also engage in the business of trading energy related products and services, which exposes us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments. We may enter into derivative instruments for NGLs or other energy related products, primarily using 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 entered into with a longer time horizon for which prices are not readily observable in the OTC market are generally classified within Level 3.

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 periodically use interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our fixed-rate debt for floating rate debt or floating rate debt for fixed-rate debt. The swaps are 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 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 other 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.

During the nine months ended September 30, 2017, we recognized impairments of property, plant and equipment, intangible assets and investment in unconsolidated affiliates of $48 million in our condensed consolidated statement of operations as summarized in the table below. Our impairment determinations involved significant assumptions and judgments. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. As such, the fair value measurements utilized within these models are classified as non-recurring Level 3 measurements in the fair value hierarchy because they are not observable from objective sources.

The following tables present the carrying value of assets measured at fair value on a non-recurring basis, by consolidated balance sheet caption and by valuation hierarchy, as of and for the three and nine months ended September 30, 2017:

	Net Carrying Value	Fair Value Measurements Using			Asset Impairments
		Level 1	Level 2	Level 3	
	(millions)				
Three and Nine Months Ended September 30, 2017					
Property, plant and equipment	$ 14	$ —	$ —	$ 14	$ 26
Intangible assets	11	—	—	11	21
Investment in unconsolidated affiliates	1	—	—	1	1
Total non-recurring assets at fair value	$ 26	$ —	$ —	$ 26	$ 48

On January 3, 2017, the Chicago Mercantile Exchange ("CME") modified its exchange rules to characterize daily variation margin amounts as "final settlement" values. The modified rule ("CME Rule 814") impacts derivative financial instruments traded on exchanges administered by the CME, including the New York Mercantile Exchange. As a result of this rule change, we are reporting the affected derivative instruments on a net basis on our balance sheet. The netting process results in the elimination of offsetting derivative assets, derivative liabilities and associated collateral cash deposits and related amounts as if the underlying derivative instruments had settled on the balance sheet date. Through December 31, 2016, we historically reported such derivatives and associated collateral balances on a gross basis. Derivative transactions and associated collateral balances cleared on exchanges other than the CME continue to be reported on a gross basis.

The following table presents the financial instruments carried at fair value as of September 30, 2017 and December 31, 2016, by condensed consolidated balance sheet caption and by valuation hierarchy, as described above:

	September 30, 2017				December 31, 2016			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets:								
Commodity derivatives (a)	$ 9	$ 21	$ 2	$ 32	$ 5	$ 28	$ 9	$ 42
Short-term investments (b)	$ 310	$ —	$ —	$ 310	$ —	$ —	$ —	$ —
Long-term assets:								
Commodity derivatives (c)	$ 1	$ 2	$ 1	$ 4	$ —	$ —	$ 5	$ 5
Current liabilities:								
Commodity derivatives (d)	$ (6)	$ (28)	$ (8)	$ (42)	$ (11)	$ (57)	$ (23)	$ (91)
Long-term liabilities:								
Commodity derivatives (e)	$ (2)	$ (6)	$ (2)	$ (10)	$ (1)	$ —	$ —	$ (1)

(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.
(e) Included in long-term 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 and nine months ended September 30, 2017 and 2016, there were no transfers between 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.

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Three months ended September 30, 2017 (a):				
Beginning balance	$ 7	$ 2	$ (2)	$ (3)
Net unrealized gains (losses) included in earnings (b)	—	2	(26)	—
Transfers out of Level 3 (c)	—	—	2	—
Settlements	—	—	2	—
CME Rule 814 adjustment	(5)	(3)	16	1
Ending balance	$ 2	$ 1	$ (8)	$ (2)
Net unrealized gains (losses) on derivatives still held included in earnings (b)	$ 3	$ 2	$ (22)	$ —
Three months ended September 30, 2016 (a):				
Beginning balance	$ 5	$ 2	$ (8)	$ (2)
Net unrealized gains included in earnings (b)	2	—	—	1
Transfers out of Level 3 (c)	(2)	—	2	—
Settlements	(1)	—	1	—
Ending balance	$ 4	$ 2	$ (5)	$ (1)
Net unrealized gains on derivatives still held included in earnings (b)	$ 1	$ —	$ —	$ 1

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Nine months ended September 30, 2017 (a):				
Beginning balance	$ 9	$ 5	$ (23)	$ —
Net unrealized gains (losses) included in earnings (b)	4	(1)	(20)	(3)
Transfers out of Level 3 (c)	(4)	—	12	—
Settlements	(2)	—	7	—
CME Rule 814 adjustment	(5)	(3)	16	1
Ending balance	$ 2	$ 1	$ (8)	$ (2)
Net unrealized gains (losses) on derivatives still held included in earnings (b)	$ 7	$ (1)	$ (21)	$ (2)
Nine months ended September 30, 2016 (a):				
Beginning balance	$ 35	$ 4	$ (23)	$ (6)
Net unrealized (losses) gains included in earnings (b)	(3)	(2)	12	5
Transfers out of Level 3 (c)	(2)	—	3	—
Settlements	(26)	—	3	—
Ending balance	$ 4	$ 2	$ (5)	$ (1)
Net unrealized gains (losses) on derivatives still held included in earnings (b)	$ 2	$ 1	$ (4)	$ 5

(a) There were no purchases, issuances or sales of derivatives or transfers into Level 3 for the three and nine months ended September 30, 2017 and 2016.
(b) Represents the amount of unrealized gains or losses for the period, included in trading and marketing gains (losses), net.
(c) Amounts transferred out of Level 3 are reflected at fair value at the end of the period.

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.

	September 30, 2017		
Product Group	Fair Value	Forward Curve Range	
	(Millions)		
Assets			
NGLs	$ 3	$0.28-$1.22	Per gallon
Liabilities			
NGLs	$ (10)	$0.21-$1.22	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.

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 and junior subordinated notes based on quotes obtained from bond dealers. We determine the fair value of borrowings under our revolving credit facility based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. We classify the fair values of our outstanding debt balances within Level 2 of the valuation hierarchy. As of September 30, 2017 and December 31, 2016, the carrying value and fair value of our total debt, including current maturities, were as follows:

	September 30, 2017		December 31, 2016	
	Carrying Value (a)	Fair Value	Carrying Value (a)	Fair Value
	(Millions)			
Total debt	$ 5,235	$ 5,365	$ 5,430	$ 5,395

(a) Excludes unamortized issuance costs.

11. Debt

	September 30, 2017	December 31, 2016
	(Millions)	
Senior notes:		
Issued November 2012, interest at 2.500% payable semi-annually, due December 2017	$ 500	$ 500
Issued February 2009, interest at 9.750% payable semiannually, due March 2019 (a)	450	450
Issued March 2014, interest at 2.700% payable semi-annually, due April 2019	325	325
Issued March 2010, interest at 5.350% payable semiannually, due March 2020 (a)	600	600
Issued September 2011, interest at 4.750% payable semiannually, due September 2021	500	500
Issued March 2012, interest at 4.950% payable semi-annually, due April 2022	350	350
Issued March 2013, interest at 3.875% payable semi-annually, due March 2023	500	500
Issued August 2000, interest at 8.125% payable semi-annually, due August 2030 (a)	300	300
Issued October 2006, interest at 6.450% payable semi-annually, due November 2036	300	300
Issued September 2007, interest at 6.750% payable semi-annually, due September 2037	450	450
Issued March 2014, interest at 5.600% payable semi-annually, due April 2044	400	400
Junior subordinated notes:		
Issued May 2013, interest at 5.850% payable semi-annually, due May 2043	550	550
Credit facility with financial institutions:		
Revolving credit facility, weighted-average variable interest rate of 2.010%, as of December 31, 2016, due May 2019	—	195
Fair value adjustments related to interest rate swap fair value hedges (a)	23	24
Unamortized issuance costs	(24)	(23)
Unamortized discount	(13)	(14)
Total debt	5,211	5,407
Current maturities of long-term debt	500	500
Total long-term debt	$ 4,711	$ 4,907

(a) The swaps associated with this debt were previously terminated. The remaining long-term fair value of approximately $23 million related to the swaps is being amortized as a reduction to interest expense through 2019, 2020 and 2030, the original maturity dates of the debt.

Credit Facility with Financial Institutions

In February 2017, we further amended our $1.25 billion senior unsecured revolving credit agreement that matures on May 1, 2019, or the Credit Agreement, to increase the aggregate commitments under the unsecured revolving credit facility to approximately $1.4 billion. The Credit Agreement is used for working capital requirements and other general partnership purposes including acquisitions.

The Credit Agreement allows for unrestricted cash and cash equivalents to be netted against consolidated indebtedness for purposes of calculating the Partnership's Consolidated Leverage Ratio (as defined in the Credit Agreement). Additionally, under the Credit Agreement, the maximum Consolidated Leverage Ratio of the Partnership as of the end of any fiscal quarter shall not exceed: (a) 5.75 to 1.0 for the quarters ending March 31, 2017 through December 31, 2017, (b) 5.50 to 1.0 for the quarter ending March 31, 2018, (c) 5.25 to 1.0 for the quarter ending June 30, 2018, and (d) 5.00 to 1.0 for the quarters thereafter; provided that, if there is a Qualified Acquisition (as defined in the Credit Agreement) during any fiscal quarter ending June 30, 2018 or thereafter, the maximum Consolidated Leverage Ratio shall not exceed 5.50 to 1.0 at the end of such quarter and at the end of the two fiscal quarters immediately thereafter.

Our cost of borrowing under the Credit Agreement is determined by a ratings-based pricing grid. Indebtedness under the Credit Agreement bears interest at either: (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 the 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 Credit Agreement incurs an annual facility fee of 0.3% based on our current credit rating. This fee is paid on drawn and undrawn portions of the approximately $1.4 billion revolving credit facility.

As of September 30, 2017, we had unused borrowing capacity of $1,373 million, net of $25 million of letters of credit, under the Credit Agreement. Our borrowing capacity may be limited by financial covenants set forth in the Credit Agreement. The financial covenants set forth in the Credit Agreement limit the Partnership's ability to incur incremental debt by $1,373 million as of September 30, 2017. Except in the case of a default, amounts borrowed under our Credit Agreement will not become due prior to the May 1, 2019 maturity date.

Senior Notes and Junior Subordinated Notes

Our senior notes and junior subordinated notes, collectively referred to as our debt securities, mature and become payable on their respective due dates, and are not subject to any sinking fund or mandatory redemption provisions. The senior notes are senior unsecured obligations that are guaranteed by the Partnership and rank equally in a right of payment with our other senior unsecured indebtedness, including indebtedness under our Credit Agreement, and the junior subordinated notes are unsecured and rank subordinate in right of payment to all of our existing and future senior indebtedness. The debt securities include an optional redemption whereby we may elect to redeem the notes, in whole or in part from time-to-time for a premium. Additionally, we may defer the payment of all or part of the interest on the junior subordinated notes for one or more periods up to five consecutive years. The underwriters’ fees and related expenses are recorded in our condensed consolidated balance sheets within the carrying amount of long-term debt and will be amortized over the term of the notes.

The maturities of our long-term debt are as follows:

	Debt Maturities
	(Millions)
2018	$ —
2019	775
2020	600
2021	500
2022	350
Thereafter	2,500
Total long-term debt	$ 4,725

12. Risk Management and Hedging Activities

Our 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

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting. The risks, strategies and instruments used to mitigate such risks, as well as the method of accounting are discussed and summarized below.

Natural Gas Asset Based Trading and Marketing

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 our natural gas storage facility 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 into 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 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 September 30, 2017.

Commodity 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 may 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. Our derivative financial instruments used to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices extend through the first quarter of 2019. The commodity derivative instruments used for our hedging programs 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 may use crude oil swaps to mitigate a portion of the commodity price risk exposure for 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. When our crude oil swaps become short-term in nature, certain crude oil derivatives may be converted to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. Crude oil and NGL transactions are primarily accomplished through the use of forward contracts that effectively exchange floating price risk for a fixed price. The type of instrument used to mitigate a portion of the risk may vary depending on our risk management objectives. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected in the current period within our condensed consolidated statements of operations as trading and marketing gains and (losses), net.

NGL Proprietary Trading

Our NGL proprietary trading activity includes trading energy related products and services. We undertake these activities through the use of fixed forward sales and purchases, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and these operations may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. These physical and financial instruments 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.

We employ established risk limits, policies and procedures to manage risks associated with our natural gas asset based trading and marketing and NGL proprietary trading.

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.

We previously had interest rate cash flow hedges and fair value hedges in place that were terminated. As the underlying transactions impact earnings, the remaining net loss deferred in AOCI relative to these cash flow hedges will be reclassified to interest expense, net from 2022 through 2030 and the remaining net loss included in long-term debt relative to these fair value hedges will be reclassified to interest expense, net from 2019 through 2030, the original maturity dates of the debt.

Credit Risk

Our principal customers range from large, natural gas marketers to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. Approximately 22% of our NGL production was committed to Phillips 66 and CPChem as of September 30, 2017. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We may use various master agreements that include language giving us the right to request collateral to mitigate credit exposure. The collateral language provides for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with our credit policy. The collateral language also provides that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our master agreements and our standard gas and NGL sales contracts contain adequate assurance provisions, which allow us to suspend deliveries and cancel agreements, or continue deliveries to the buyer after the buyer provides security for payment in a satisfactory form.

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 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.

- Our ISDA counterparties generally have collateral thresholds of zero, 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 Credit Agreement. As of September 30, 2017, 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 interest rate swap instruments are in either a net asset or net liability position. As of September 30, 2017, we had less than $1 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability 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 September 30, 2017, we have not been required to post additional collateral. Although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of September 30, 2017, the net liability position would be offset by contracts in a net asset position.

Collateral

As of September 30, 2017, we had cash deposits of $42 million, included in collateral cash deposits in our condensed consolidated balance sheets, and letters of credit of $13 million with counterparties to secure our obligations to provide future services or to perform under financial contracts. Additionally, as of September 30, 2017, we held cash of $19 million, included in other current liabilities in our condensed consolidated balance sheet, related to cash postings by third parties and letters of credit of $36 million from counterparties to secure their future performance under financial or physical contracts. Collateral amounts held or posted may be fixed or may vary, depending on the value of the underlying contracts, and could cover normal purchases and sales, services, trading and hedging contracts. In many cases, we and our counterparties have publicly disclosed credit ratings, which may impact the amounts of collateral requirements.

Physical forward contracts and financial derivatives are generally cash settled at the expiration of the contract term. These transactions are generally subject to specific credit provisions within the contracts that would allow the seller, at its discretion, to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment satisfactory to the seller.

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:

	September 30, 2017			December 31, 2016		
	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments	Net Amount	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments	Net Amount
	(Millions)					
Assets:						
Commodity derivatives	$ 36	$ —	$ 36	$ 47	$ —	$ 47
Liabilities:						
Commodity derivatives	$ (52)	$ —	$ (52)	$ (92)	$ —	$ (92)

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 September 30, 2017 and December 31, 2016.

Balance Sheet Line Item	September 30, 2017	December 31, 2016	Balance Sheet Line Item	September 30, 2017	December 31, 2016
	(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	$ 32	$ 42	Unrealized losses on derivative instruments — current	$ (42)	$ (91)
Unrealized gains on derivative instruments — long-term	4	5	Unrealized losses on derivative instruments — long-term	(10)	(1)
Total	$ 36	$ 47	Total	$ (52)	$ (92)

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 September 30, 2017:

	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)	$ (4)	$ (6)	$ 1	$ (9)
Net deferred (losses) gains in AOCI (ending balance)	$ (4)	$ (6)	$ 1	$ (9)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$ (1)	$ —	$ —	$ (1)

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 nine months ended September 30, 2017:

	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)	$ (3)	$ (6)	$ 1	$ (8)
Losses reclassified from AOCI to earnings — effective portion	1	—	—	1
Deficit purchase price under carrying value of the Transaction	$ (2)	$ —	$ —	$ (2)
Net deferred (losses) gains in AOCI (ending balance)	$ (4)	$ (6)	$ 1	$ (9)

(a) Relates to Discovery, an unconsolidated affiliate.

For the three and nine months ended September 30, 2017, no derivative losses attributable to the ineffective portion or to amounts excluded from effectiveness testing were recognized in trading and marketing gains, net or interest expense in our condensed consolidated statements of operations. For the three and nine months ended September 30, 2017, no derivative losses were reclassified from AOCI to trading and marketing gains, 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.

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 September 30, 2016:

	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)	$ (3)	$ (6)	$ 1	$ (8)
Net deferred (losses) gains in AOCI (ending balance)	$ (3)	$ (6)	$ 1	$ (8)

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 nine months ended September 30, 2016:

	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)	$ (3)	$ (6)	$ 1	$ (8)
Net deferred (losses) gains in AOCI (ending balance)	$ (3)	$ (6)	$ 1	$ (8)

(a) Relates to Discovery, an unconsolidated affiliate.

For the three and nine months ended September 30, 2016, no derivative losses attributable to the ineffective portion or to amounts excluded from effectiveness testing were recognized in trading and marketing gains or losses, net or interest expense in our condensed consolidated statements of operations. For the three and nine months ended September 30, 2016, no derivative losses were reclassified from AOCI to trading and marketing gains or losses, 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.

Changes in the 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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Millions)			
Realized gains	$ 16	$ 6	$ 9	$ 90
Unrealized (losses) gains	(59)	9	1	(80)
Trading and marketing (losses) gains, net	$ (43)	$ 15	$ 10	$ 10

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

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.

	September 30, 2017			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net Short Position (Bbls)	Net Short Position (MMBtu)	Net (Short) Long Position (Bbls)	Net Long Position (MMBtu)
2017	(81,000)	(20,888,000)	(9,288,558)	2,680,000
2018	(1,803,000)	(29,277,400)	(13,417,484)	9,190,000
2019	(367,000)	—	(2,353,300)	9,317,500
2020	(50,000)	—	238,548	3,660,000

	September 30, 2016			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net Short Position (Bbls)	Net Short Position (MMBtu)	Net (Short) Long Position (Bbls)	Net (Short) Long Position (MMBtu)
2016	(380,000)	(5,915,500)	(10,018,903)	(512,500)
2017	(964,000)	(27,686,850)	(7,725,057)	6,515,000
2018	—	—	150,216	—
2019	(40,000)	—	(1,984)	—
2020	(50,000)	—	240,000	—

13. Partnership Equity and Distributions

As part of the Transaction, Phillips 66 and Enbridge agreed, if required, to provide a reduction to incentive distributions payable to our General Partner under our Partnership Agreement of up to $100 million annually through 2019 to target an approximate 1.0 times distribution coverage ratio. Under the terms of our amended partnership agreement, the amount of incentive distributions paid to our General Partner will be evaluated by our General Partner on both a quarterly and annual basis and may be reduced each quarter by an amount determined by our General Partner (the “IDR giveback”). If no determination is made by our General Partner, the quarterly IDR giveback will be $20 million. The IDR giveback, of up to $100 million annually, will be subject to a true-up at the end of the year by taking our total distributable cash flow (as adjusted under our amended partnership agreement) less the total annual distribution payable to our unitholders, adjusted to target an approximate 1.0 times coverage ratio. Distributions paid to the holders of the Partnership's incentive distribution rights were reduced by $20 million and $40 million during the three and nine month periods ended September 30, 2017, respectively, in accordance with the Third Amendment to the Partnership Agreement.

In January 2017, we issued 28,552,480 common units to DCP Midstream, LLC and 2,550,644 general partner units to the General Partner in a private placement as consideration for the Transaction that closed on January 1, 2017. For additional information regarding the Transaction, see Note 3 - Acquisitions.

During the nine months ended September 30, 2017 and 2016, we issued no common units pursuant to our 2014 equity distribution agreement.

The following table presents our cash distributions paid in 2017 and 2016:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
August 14, 2017	$ 0.7800	$ 134
May 15, 2017	0.7800	135
February 14, 2017	0.7800	121
November 14, 2016	0.7800	120
August 12, 2016	0.7800	121
May 13, 2016	0.7800	121
February 12, 2016	0.7800	121

14. 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.

15. 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 results of operations, financial position, or cash flow.

Insurance — Our insurance coverage is carried with third-party insurers and with an affiliate of Phillips 66. Our insurance coverage includes: (1) general liability insurance covering third-party exposures; (2) statutory workers’ compensation insurance; (3) automobile liability insurance for all owned, non-owned and hired vehicles; (4) excess liability insurance above the established primary limits for general liability and automobile liability insurance; (5) property insurance, which covers the replacement value of real and personal property and includes business interruption; and (6) insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

Environmental — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, fractionating, 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, in some cases, local levels that relate to worker safety, air and water quality, solid and hazardous 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, worker safety standards, and safety standards applicable to our various facilities. In addition, there is increasing focus (i) 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 and the resulting supply of NGLs, (ii) from federal regulatory agencies regarding pipeline system safety which could impose additional regulatory burdens and increase the cost of our operations, and (iii) from state and federal regulatory officials regarding the emission of greenhouse gases which could impose regulatory burdens and increase the cost of our operations. 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 existing laws and regulations will not have a material adverse effect on our results of operations, financial position or cash flows.

16. Business Segments

Concurrent with the completion of the Transaction in the first quarter of 2017, management reevaluated our reportable segments and determined that our operations are organized into two reportable segments: (i) Gathering and Processing and (ii) Logistics and Marketing. Segment information for prior periods has been retrospectively adjusted to furnish comparative information similar to the pooling method to reflect these reportable segments. 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. Our Gathering and Processing reportable segment includes operating segments that have been aggregated based on the nature of the products and services provided. Gross margin is a performance measure utilized by management to monitor the operations of each segment. The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies included as Exhibit 99.4 in the May 2017 8-K.

Our Gathering and Processing segment consists of gathering, compressing, treating, processing natural gas, producing and fractionating NGLs, and recovering and selling condensate. Our Logistics and Marketing segment includes transporting, trading, marketing, and storing natural gas and NGLs, fractionating NGLs, and wholesale propane logistics. The remainder of our business operations is presented as “Other,” and consists of unallocated corporate costs. Elimination of inter-segment transactions are reflected in the eliminations column. The following tables set forth our segment information:

Three Months Ended September 30, 2017:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
			(Millions)		
Total operating revenue	$ 1,337	$ 1,913	$ —	$ (1,195)	$ 2,055
Gross margin (a)	$ 303	$ 57	$ —	$ —	$ 360
Operating and maintenance expense	(154)	(9)	(5)	—	(168)
Depreciation and amortization expense	(85)	(4)	(5)	—	(94)
General and administrative expense	(2)	(3)	(64)	—	(69)
Asset impairments	(48)	—	—	—	(48)
Other (expense) income	—	(1)	1	—	—
Earnings from unconsolidated affiliates	15	59	—	—	74
Interest expense	—	—	(73)	—	(73)
Income tax expense	—	—	(2)	—	(2)
Net income (loss)	$ 29	$ 99	$ (148)	$ —	$ (20)
Net income attributable to noncontrolling interests	—	—	—	—	—
Net income (loss) attributable to partners	$ 29	$ 99	$ (148)	$ —	$ (20)
Non-cash derivative mark-to-market (b)	$ (51)	$ (8)	$ —	$ —	$ (59)
Capital expenditures	$ 91	$ 1	$ 7	$ —	$ 99
Investments in unconsolidated affiliates, net	$ 1	$ 28	$ —	$ —	$ 29

Three Months Ended September 30, 2016:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
			(Millions)		
Total operating revenue	$ 1,217	$ 1,641	$ —	$ (1,035)	$ 1,823
Gross margin (a)	$ 335	$ 51	$ —	$ —	$ 386
Operating and maintenance expense	(146)	(13)	(2)	—	(161)
Depreciation and amortization expense	(85)	(4)	(5)	—	(94)
General and administrative expense	(2)	(2)	(60)	—	(64)
Other expense	(13)	—	(1)	—	(14)
Gain on sale of assets, net	25	16	—	—	41
Restructuring costs	—	—	(2)	—	(2)
Earnings from unconsolidated affiliates	20	55	—	—	75
Interest expense	—	—	(77)	—	(77)
Income tax expense	—	—	(1)	—	(1)
Net income (loss)	$ 134	$ 103	$ (148)	$ —	$ 89
Net income attributable to noncontrolling interests	—	—	—	—	—
Net income (loss) attributable to partners	$ 134	$ 103	$ (148)	$ —	$ 89
Non-cash derivative mark-to-market (b)	$ (5)	$ 14	$ —	$ —	$ 9
Capital expenditures	$ 18	$ 4	$ 8	$ —	$ 30
Investments in unconsolidated affiliates, net	$ —	$ 11	$ —	$ —	$ 11

Nine Months Ended September 30, 2017:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
			(Millions)		
Total operating revenue	$ 3,965	$ 5,596	$ —	$ (3,436)	$ 6,125
Gross margin (a)	$ 1,021	$ 165	$ —	$ —	$ 1,186
Operating and maintenance expense	(469)	(31)	(13)	—	(513)
Depreciation and amortization expense	(256)	(11)	(15)	—	(282)
General and administrative expense	(15)	(8)	(179)	—	(202)
Asset impairments	(48)	—	—	—	(48)
Other expense	(3)	(12)	—	—	(15)
Gain on sale of assets, net	34	—	—	—	34
Earnings from unconsolidated affiliates	59	175	—	—	234
Interest expense	—	—	(219)	—	(219)
Income tax expense	—	—	(5)	—	(5)
Net income (loss)	$ 323	$ 278	$ (431)	$ —	$ 170
Net income attributable to noncontrolling interests	(1)	—	—	—	(1)
Net income (loss) attributable to partners	$ 322	$ 278	$ (431)	$ —	$ 169
Non-cash derivative mark-to-market (b)	$ (4)	$ 5	$ —	$ —	$ 1
Capital expenditures	$ 237	$ 2	$ 19	$ —	$ 258
Investments in unconsolidated affiliates, net	$ 1	$ 69	$ —	$ —	$ 70

Nine Months Ended September 30, 2016:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
			(Millions)		
Total operating revenue	$ 3,190	$ 4,362	$ —	$ (2,642)	$ 4,910
Gross margin (a)	$ 892	$ 152	$ —	$ —	$ 1,044
Operating and maintenance expense	(458)	(33)	(15)	—	(506)
Depreciation and amortization expense	(258)	(12)	(14)	—	(284)
General and administrative expense	(10)	(7)	(170)	—	(187)
Other income (expense)	74	(5)	(1)	—	68
Gain on sale of assets, net	19	16	—	—	35
Restructuring costs	—	—	(10)	—	(10)
Earnings from unconsolidated affiliates	52	162	—	—	214
Interest expense	—	—	(235)	—	(235)
Income tax expense	—	—	(6)	—	(6)
Net income (loss)	$ 311	$ 273	$ (451)	$ —	$ 133
Net income attributable to noncontrolling interests	(1)	—	—	—	(1)
Net income (loss) attributable to partners	$ 310	$ 273	$ (451)	$ —	$ 132
Non-cash derivative mark-to-market (b)	$ (73)	$ (7)	$ —	$ —	$ (80)
Non-cash lower of cost or market adjustments	$ —	$ 3	$ —	$ —	$ 3
Capital expenditures	$ 90	$ 7	$ 16	$ —	$ 113
Investments in unconsolidated affiliates, net	$ —	$ 38	$ —	$ —	$ 38

(a) Gross margin consists of total operating revenues, including trading and marketing gains and losses, less purchases of natural gas and NGLs. Gross margin is viewed as a non-GAAP financial 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.

	September 30, 2017	December 31, 2016
	(Millions)	
Segment long-term assets:		
Gathering and Processing	$ 8,884	$ 9,053
Logistics and Marketing	3,293	3,278
Other (a)	283	286
Total long-term assets	12,460	12,617
Current assets	1,311	994
Total assets	$ 13,771	$ 13,611

(a) Other long-term assets not allocable to segments consist of corporate leasehold improvements and other long-term assets.

17. Supplemental Cash Flow Information

	Nine Months Ended September 30,	
	2017	2016
	(Millions)	
Cash paid for interest:		
Cash paid for interest, net of amounts capitalized	$ 218	$ 248
Cash paid for income taxes, net of income tax refunds	$ 2	$ 2
Non-cash investing and financing activities:		
Property, plant and equipment acquired with accounts payable and accrued liabilities	$ 27	$ 15
Other non-cash changes in property, plant and equipment	$ (1)	$ 1
Issuance of common and general partner units	$ 1,125	$ —
Deficit purchase price in the Transaction	$ 3,094	$ —

18. Condensed Consolidating Financial Information

The following condensed consolidating financial information presents the results of operations, financial position and cash flows of DCP Midstream, 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, 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.

	Condensed Consolidating Balance Sheet September 30, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 310	$ 2	$ —	$ 312
Accounts receivable, net	—	—	846	—	846
Inventories	—	—	62	—	62
Other	—	—	91	—	91
Total current assets	—	310	1,001	—	1,311
Property, plant and equipment, net	—	—	8,926	—	8,926
Goodwill and intangible assets, net	—	—	340	—	340
Advances receivable — consolidated subsidiaries	2,563	2,031	—	(4,594)	—
Investments in consolidated subsidiaries	4,453	7,392	—	(11,845)	—
Investments in unconsolidated affiliates	—	—	3,002	—	3,002
Other long-term assets	—	—	192	—	192
Total assets	$ 7,016	$ 9,733	$ 13,461	$ (16,439)	$ 13,771
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 69	$ 1,215	$ —	$ 1,284
Current maturities of long-term debt	—	500	—	—	500
Advances payable — consolidated subsidiaries	—	—	4,594	(4,594)	—
Long-term debt	—	4,711	—	—	4,711
Other long-term liabilities	—	—	233	—	233
Total liabilities	—	5,280	6,042	(4,594)	6,728
Commitments and contingent liabilities					
Equity:					
Partners’ equity:					
Net equity	7,016	4,457	7,397	(11,845)	7,025
Accumulated other comprehensive loss	—	(4)	(5)	—	(9)
Total partners’ equity	7,016	4,453	7,392	(11,845)	7,016
Noncontrolling interests	—	—	27	—	27
Total equity	7,016	4,453	7,419	(11,845)	7,043
Total liabilities and equity	$ 7,016	$ 9,733	$ 13,461	$ (16,439)	$ 13,771

Condensed Consolidating Balance Sheet
December 31, 2016

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ —	$ 1	$ —	$ 1
Accounts receivable, net	—	—	792	—	792
Inventories	—	—	72	—	72
Other	—	—	129	—	129
Total current assets	—	—	994	—	994
Property, plant and equipment, net	—	—	9,069	—	9,069
Goodwill and intangible assets, net	—	—	373	—	373
Advances receivable — consolidated subsidiaries	2,953	2,760	—	(5,713)	—
Investments in consolidated subsidiaries	3,868	6,587	—	(10,455)	—
Investments in unconsolidated affiliates	—	—	2,969	—	2,969
Other long-term assets	—	—	206	—	206
Total assets	$ 6,821	$ 9,347	$ 13,611	$ (16,168)	$ 13,611
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 72	$ 1,051	$ —	$ 1,123
Current maturities of long-term debt	—	500	—	—	500
Advances payable — consolidated subsidiaries	—	—	5,713	(5,713)	—
Long-term debt	—	4,907	—	—	4,907
Other long-term liabilities	—	—	228	—	228
Total liabilities	—	5,479	6,992	(5,713)	6,758
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Net equity	6,821	3,871	6,592	(10,455)	6,829
Accumulated other comprehensive loss	—	(3)	(5)	—	(8)
Total partners' equity	6,821	3,868	6,587	(10,455)	6,821
Noncontrolling interests	—	—	32	—	32
Total equity	6,821	3,868	6,619	(10,455)	6,853
Total liabilities and equity	$ 6,821	$ 9,347	$ 13,611	$ (16,168)	$ 13,611

Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2017

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, NGLs and condensate	$ —	$ —	$ 1,936	$ —	$ 1,936
Transportation, processing and other	—	—	162	—	162
Trading and marketing losses, net	—	—	(43)	—	(43)
Total operating revenues	—	—	2,055	—	2,055
Operating costs and expenses:					
Purchases of natural gas and NGLs	—	—	1,695	—	1,695
Operating and maintenance expense	—	—	168	—	168
Depreciation and amortization expense	—	—	94	—	94
General and administrative expense	—	—	69	—	69
Asset impairments	—	—	48	—	48
Total operating costs and expenses	—	—	2,074	—	2,074
Operating loss	—	—	(19)	—	(19)
Interest expense	—	(73)	—	—	(73)
(Loss) income from consolidated subsidiaries	(20)	53	—	(33)	—
Earnings from unconsolidated affiliates	—	—	74	—	74
(Loss) income before income taxes	(20)	(20)	55	(33)	(18)
Income tax expense	—	—	(2)	—	(2)
Net (loss) income	(20)	(20)	53	(33)	(20)
Net income attributable to noncontrolling interests	—	—	—	—	—
Net (loss) income attributable to partners	$ (20)	$ (20)	$ 53	$ (33)	$ (20)

Condensed Consolidating Statement of Comprehensive (Loss) Income
Three Months Ended September 30, 2017

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net (loss) income	$ (20)	$ (20)	$ 53	$ (33)	$ (20)
Total other comprehensive income	—	—	—	—	—
Total comprehensive (loss) income	(20)	(20)	53	(33)	(20)
Total comprehensive income attributable to noncontrolling interests	—	—	—	—	—
Total comprehensive (loss) income attributable to partners	$ (20)	$ (20)	$ 53	$ (33)	$ (20)

Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2016

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, NGLs and condensate	$ —	$ —	$ 1,646	$ —	$ 1,646
Transportation, processing and other	—	—	162	—	162
Trading and marketing gains, net	—	—	15	—	15
Total operating revenues	—	—	1,823	—	1,823
Operating costs and expenses:					
Purchases of natural gas and NGLs	—	—	1,437	—	1,437
Operating and maintenance expense	—	—	161	—	161
Depreciation and amortization expense	—	—	94	—	94
General and administrative expense	—	—	64	—	64
Gain on sale of assets, net	—	—	(41)	—	(41)
Restructuring costs	—	—	2	—	2
Other expense, net	—	—	14	—	14
Total operating costs and expenses	—	—	1,731	—	1,731
Operating income	—	—	92	—	92
Interest expense, net	—	(77)	—	—	(77)
Income from consolidated subsidiaries	89	166	—	(255)	—
Earnings from unconsolidated affiliates	—	—	75	—	75
Income before income taxes	89	89	167	(255)	90
Income tax expense	—	—	(1)	—	(1)
Net income	89	89	166	(255)	89
Net income attributable to noncontrolling interests	—	—	—	—	—
Net income attributable to partners	$ 89	$ 89	$ 166	$ (255)	$ 89

Condensed Consolidating Statement of Comprehensive Income
Three Months Ended September 30, 2016

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 89	$ 89	$ 166	$ (255)	$ 89
Total other comprehensive income	—	—	—	—	—
Total comprehensive income	89	89	166	(255)	89
Total comprehensive income attributable to noncontrolling interests	—	—	—	—	—
Total comprehensive income attributable to partners	$ 89	$ 89	$ 166	$ (255)	$ 89

Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2017

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, NGLs and condensate	$ —	$ —	$ 5,641	$ —	$ 5,641
Transportation, processing and other	—	—	474	—	474
Trading and marketing gains, net	—	—	10	—	10
Total operating revenues	—	—	6,125	—	6,125
Operating costs and expenses:					
Purchases of natural gas and NGLs	—	—	4,939	—	4,939
Operating and maintenance expense	—	—	513	—	513
Depreciation and amortization expense	—	—	282	—	282
General and administrative expense	—	—	202	—	202
Asset impairments	—	—	48	—	48
Gain on sale of assets, net	—	—	(34)	—	(34)
Other expense, net	—	—	15	—	15
Total operating costs and expenses	—	—	5,965	—	5,965
Operating income	—	—	160	—	160
Interest expense, net	—	(219)	—	—	(219)
Income from consolidated subsidiaries	169	388	—	(557)	—
Earnings from unconsolidated affiliates	—	—	234	—	234
Income before income taxes	169	169	394	(557)	175
Income tax expense	—	—	(5)	—	(5)
Net income	169	169	389	(557)	170
Net income attributable to noncontrolling interests	—	—	(1)	—	(1)
Net income attributable to partners	$ 169	$ 169	$ 388	$ (557)	$ 169

Condensed Consolidating Statement of Comprehensive Income
Nine Months Ended September 30, 2017

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Net income	$ 169	$ 169	$ 389	$ (557)	$ 170
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	170	170	389	(558)	171
Total comprehensive income attributable to noncontrolling interests	—	—	(1)	—	(1)
Total comprehensive income attributable to partners	$ 170	$ 170	$ 388	$ (558)	$ 170

Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2016

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Operating revenues:					
Sales of natural gas, NGLs and condensate	$ —	$ —	$ 4,431	$ —	$ 4,431
Transportation, processing and other	—	—	469	—	469
Trading and marketing gains, net	—	—	10	—	10
Total operating revenues	—	—	4,910	—	4,910
Operating costs and expenses:					
Purchases of natural gas and NGLs	—	—	3,866	—	3,866
Operating and maintenance expense	—	—	506	—	506
Depreciation and amortization expense	—	—	284	—	284
General and administrative expense	—	—	187	—	187
Gain on sale of assets, net	—	—	(35)	—	(35)
Restructuring costs	—	—	10	—	10
Other income, net	—	—	(68)	—	(68)
Total operating costs and expenses	—	—	4,750	—	4,750
Operating income	—	—	160	—	160
Interest expense, net	—	(235)	—	—	(235)
Income from consolidated subsidiaries	132	367	—	(499)	—
Earnings from unconsolidated affiliates	—	—	214	—	214
Income before income taxes	132	132	374	(499)	139
Income tax expense	—	—	(6)	—	(6)
Net income	132	132	368	(499)	133
Net income attributable to noncontrolling interests	—	—	(1)	—	(1)
Net income attributable to partners	$ 132	$ 132	$ 367	$ (499)	$ 132

Condensed Consolidating Statement of Comprehensive Income
Nine Months Ended September 30, 2016

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Net income	$ 132	$ 132	$ 368	$ (499)	$ 133
Total other comprehensive income	—	—	—	—	—
Total comprehensive income	132	132	368	(499)	133
Total comprehensive income attributable to noncontrolling interests	—	—	(1)	—	(1)
Total comprehensive income attributable to partners	$ 132	$ 132	$ 367	$ (499)	$ 132

	Condensed Consolidating Statement of Cash Flows Nine Months Ended September 30, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (217)	$ 901	$ —	$ 684
INVESTING ACTIVITIES:					
Intercompany transfers	390	724	—	(1,114)	—
Capital expenditures	—	—	(258)	—	(258)
Investments in unconsolidated affiliates	—	—	(70)	—	(70)
Proceeds from sale of assets	—	—	130	—	130
Net cash provided by (used in) investing activities	390	724	(198)	(1,114)	(198)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	(1,114)	1,114	—
Payments of long-term debt	—	(195)	—	—	(195)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	418	—	418
Distributions to limited partners and general partner	(390)	—	—	—	(390)
Distributions to noncontrolling interests	—	—	(6)	—	(6)
Other	—	(2)	—	—	(2)
Net cash used in by financing activities	(390)	(197)	(702)	1,114	(175)
Net change in cash and cash equivalents	—	310	1	—	311
Cash and cash equivalents, beginning of period	—	—	1	—	1
Cash and cash equivalents, end of period	$ —	$ 310	$ 2	$ —	$ 312

	Condensed Consolidating Statements of Cash Flows Nine Months Ended September 30, 2016				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (244)	$ 765	$ —	$ 521
INVESTING ACTIVITIES:					
Intercompany transfers	362	559	—	(921)	—
Capital expenditures	—	—	(113)	—	(113)
Investments in unconsolidated affiliates	—	—	(38)	—	(38)
Proceeds from sale of assets	—	—	160	—	160
Net cash provided by investing activities	362	559	9	(921)	9
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	(921)	921	—
Proceeds from long-term debt	—	2,926	—	—	2,926
Payments of long-term debt	—	(3,216)	—	—	(3,216)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	150	—	150
Distributions to limited partners and general partner	(362)	—	—	—	(362)
Distributions to noncontrolling interests	—	—	(6)	—	(6)
Other	—	(10)	—	—	(10)
Net cash used in financing activities	(362)	(300)	(777)	921	(518)
Net change in cash and cash equivalents	—	15	(3)	—	12
Cash and cash equivalents, beginning of period	—	—	3	—	3
Cash and cash equivalents, end of period	$ —	$ 15	$ —	$ —	$ 15

19. Subsequent Events

On October 19, 2017, we announced that the board of directors of the General Partner declared a quarterly distribution of $0.78 per unit. The distribution is payable on November 14, 2017 to unitholders of record on November 7, 2017.

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 on Form 10-Q and the consolidated financial statements and notes thereto included as Exhibit 99.4 in the May 2017 8-K.

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. Concurrent with the completion of the Transaction in the first quarter of 2017, management reevaluated our reportable segments and determined that our operations are organized into two reportable segments: (i) Gathering and Processing and (ii) Logistics and Marketing. Segment information for earlier periods has been restated to reflect these reportable segments. Our Gathering and Processing segment includes operating segments that have been aggregated based on the nature of the products and services provided. Our Gathering and Processing segment consists of gathering, compressing, treating, and processing natural gas, producing and fractionating NGLs, and recovering and selling condensate. Our Logistics and Marketing segment includes transporting, trading, marketing and storing natural gas and NGLs, fractionating NGLs and wholesale propane logistics. The remainder of our business operations is presented as "Other", and consists of unallocated corporate costs.

Our business is impacted by commodity prices and volumes. We mitigate a portion of commodity price risk on an overall Partnership basis by growing our fee based assets and by executing on our hedging program, in which we hedge commodity prices associated with a portion of our expected natural gas, NGL and condensate equity volumes in our Gathering and Processing segment. 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. If commodity prices weaken for a sustained period, our volumes may be impacted, particularly as producers are curtailing or redirecting drilling. Drilling activity levels vary by geographic area; we will continue to target our strategy in geographic areas where we expect producer drilling activity.

Our long-term view is that commodity prices will be at levels we believe will support growth in natural gas, condensate and NGL production. We believe future commodity prices will be influenced by the severity of winter and summer weather, the level of North American production and drilling activity by exploration and production companies and the balance of trade between imports and exports of liquid natural gas, NGLs and crude oil.

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 and expanding facilities to convert chemical plants from a heavier oil-based feedstock to lighter NGL-based feedstocks, including ethane. This increased demand expected in the next year should provide support for the increasing supply of ethane. As these facilities commence operations, ethane prices could remain weak with supply in excess of demand. In addition, export facilities are being expanded and built, which provide support for the increasing supply of NGLs. Although there can be, and has been, volatility in NGL prices, longer term we believe there will be sufficient demand in NGLs to support increasing supply.

Although we have seen a number of bankruptcies by producers in recent years, we believe our contract structure with our producers protects us from a credit perspective since we generally hold the product, sell it and withhold our fees prior to remittance of payments to the producer. Currently, our top 20 producers account for a majority of the total natural gas that we gather and process and of these top 20 producers, eight have investment grade credit ratings while the remainder do not.

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.

We believe we are positioned to withstand current and future commodity price volatility as a result of the following:

- Our growing fee-based business represents a significant portion of our margins.
- We have positive operating cash flow from our well-positioned and diversified assets.
- We have a well-defined and targeted hedging program.
- We manage our disciplined capital growth program with a significant focus on fee-based agreements and projects with long term volume outlooks.

- We believe we have a solid capital structure and balance sheet.
- We believe we have access to sufficient capital to fund our growth.

We have engaged in a disciplined growth strategy in recent years focusing on our key areas of operations. Our targeted strategy may take numerous forms such as organic build opportunities within our footprint, joint venture opportunities, and acquisitions. Growth opportunities will be evaluated in cooperation with producers and customers based on the expected level of drilling activity in these geographic regions and the impacts of higher costs of capital.

Some of our growth projects include the following:

- Within our Gathering and Processing segment, we increased capacity in the DJ Basin by up to 40 MMcf/d starting in June 2017 by placing additional field compression and plant bypass infrastructure in service.
- We are constructing a 200 MMcf/d natural gas processing plant, the Mewbourn 3 plant, and further expanding our Grand Parkway gathering system, both of which are located in the DJ Basin and expected to be in service in the fourth quarter of 2018.
- Our 200 MMcf/d O'Connor 2 plant and associated gathering infrastructure, located in the DJ Basin, is also approved and expected to be in service in mid 2019.
- Within our Logistics and Marketing segment, we are currently expanding the Sand Hills pipeline to 365 MBbls/d, expected to be completed late fourth quarter of 2017 or early first quarter of 2018, and have multiple Sand Hills lateral connections in flight throughout 2017.
- Further Sand Hills pipeline expansion to 450 MBbls/d is progressing and includes a partial looping of the pipeline and the addition of new pump stations, and is expected to be in service in the third quarter of 2018.
- We signed a letter of intent with respect to the joint development of the Gulf Coast Express pipeline project (GCX project) with Kinder Morgan Texas Pipeline LLC and Targa Resources Corp, which would provide an outlet for increased natural gas production from the Permian Basin to growing markets along the Texas Gulf Coast. The capacity of the GCX project is expected to be 1.92 Bcf/d. The mostly 42-inch pipeline would traverse approximately 500 miles and be in service in the second half of 2019, pending final shipper commitments and a final investment decision by all three entities. Under the terms of the letter of intent, we will own a 25 percent equity interest in the project and would commit significant volumes.

Recent Events

We are jointly developing the Cheyenne Connector pipeline (“Cheyenne Connector”) with Tallgrass Energy Partners, LP and Western Gas Partners, LP, in which we have an option to invest in at a later date. Tallgrass Energy Partners, LP has announced the launch of an open season to transport natural gas on the Cheyenne Connector from the DJ Basin to the Rockies Express Pipeline (“REX”) Cheyenne Hub just south of the Colorado-Wyoming border. Cheyenne Connector has signed long-term precedent agreements to transport at least 600 MMcf/d of natural gas with affiliates of Anadarko Petroleum Corporation and the Partnership. Cheyenne Connector will provide takeaway solutions for DJ Basin gas producers, connecting natural gas to REX’s Cheyenne Hub where it can then be delivered to numerous demand markets across the country on either REX or other interconnected pipelines.

In August 2017, we experienced business interruptions at certain of our assets as a result of Hurricane Harvey. Our logistics facilities, including Sand Hills, Southern Hills and other NGL pipelines connecting to the Gulf Coast remained operational for the duration of the storm, but volumes were impacted due to downstream constraints. Based on current assessments, no significant damage has been identified to our assets, however, final assessments are still underway.

We announced a quarterly distribution of $0.78 per unit for the third quarter of 2017. This distribution per unit remains unchanged from the previous quarter and the third quarter of 2016.

General Trends and Outlook

During 2017, our strategic objectives will continue to focus on maintaining stable Distributable Cash Flows from our existing assets and executing on opportunities to sustain our long-term Distributable Cash Flows in light of the significant changes to our business resulting from the Transaction. 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. Our 2017 plan includes maintenance capital expenditures of between $100 million and $145 million, and expansion capital expenditures between $325 million and $375 million associated with approved projects. We forecast maintenance spending to be at the low end of the range, and expansion spending to be at the high end of the range. Expansion capital expenditures include the construction of the Mewbourn 3 plant, Grand Parkway Phase 2 and O'Connor bypass in our DJ Basin system, and the capacity expansions of the Sand Hills pipeline, which are shown as an investment in unconsolidated affiliates in our condensed consolidated statements of cash flows.

For an in-depth discussion of factors that may significantly affect our results, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Factors That May Significantly Affect Our Results” included as Exhibit 99.3 in our current report on the May 2017 8-K.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our condensed consolidated results of operations for the three and nine months ended September 30, 2017 and 2016. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2017 vs. 2016		Variance Nine Months 2017 vs. 2016	
	2017	2016	2017	2016	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)							
Operating revenues (a):								
Gathering and Processing	$ 1,337	$ 1,217	$ 3,965	$ 3,190	$ 120	10 %	$ 775	24 %
Logistics and Marketing	1,913	1,641	5,596	4,362	272	17 %	1,234	28 %
Inter-segment eliminations	(1,195)	(1,035)	(3,436)	(2,642)	160	15 %	794	30 %
Total operating revenues	2,055	1,823	6,125	4,910	232	13 %	1,215	25 %
Purchases of natural gas and NGLs								
Gathering and Processing	(1,034)	(882)	(2,944)	(2,298)	152	17 %	646	28 %
Logistics and Marketing	(1,856)	(1,590)	(5,431)	(4,210)	266	17 %	1,221	29 %
Inter-segment eliminations	1,195	1,035	3,436	2,642	160	15 %	794	30 %
Total purchases	(1,695)	(1,437)	(4,939)	(3,866)	258	18 %	1,073	28 %
Operating and maintenance expense	(168)	(161)	(513)	(506)	7	4 %	7	1 %
Depreciation and amortization expense	(94)	(94)	(282)	(284)	—	— %	(2)	(1)%
General and administrative expense	(69)	(64)	(202)	(187)	5	8 %	15	8 %
Asset impairments	(48)	—	(48)	—	48	*	48	*
Other (expense) income, net	—	(14)	(15)	68	14	*	(83)	*
Earnings from unconsolidated affiliates (b)	74	75	234	214	(1)	(1)%	20	9 %
Interest expense	(73)	(77)	(219)	(235)	(4)	(5)%	(16)	(7)%
Income tax expense	(2)	(1)	(5)	(6)	1	*	(1)	(17)%
Restructuring costs	—	(2)	—	(10)	(2)	*	(10)	*
Gain on sale of assets, net	—	41	34	35	(41)	*	(1)	*
Net income attributable to noncontrolling interests	—	—	(1)	(1)	—	*	—	*
Net (loss) income attributable to partners	$ (20)	$ 89	$ 169	$ 132	$ (109)	*	$ 37	28 %
Other data:								
Gross margin (c):								
Gathering and Processing	$ 303	$ 335	$ 1,021	$ 892	$ (32)	(10)%	$ 129	14 %
Logistics and Marketing	57	51	165	152	$ 6	12 %	$ 13	9 %
Total gross margin	$ 360	$ 386	$ 1,186	$ 1,044	$ (26)	(7)%	$ 142	14 %
Non-cash commodity derivative mark-to-market	$ (59)	$ 9	$ 1	$ (80)	$ (68)	*	$ 81	*
Natural gas wellhead (MMcf/d) (d)	4,460	5,005	4,508	5,230	(545)	(11)%	(722)	(14)%
NGL gross production (MBbls/d) (d)	376	392	365	401	(16)	(4)%	(36)	(9)%
NGL pipelines throughput (MBbls/d) (d)	462	434	447	421	28	6 %	26	6 %

* Percentage change is not meaningful.

(a) Operating revenues include the impact of trading and marketing gains (losses), net.

(b) 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.
(c) Gross margin consists of total operating revenues less purchases of natural gas and NGLs. Segment gross margin for each segment consists of total operating revenues for that segment less purchases of natural gas and NGLs for that segment. Please read "Reconciliation of Non-GAAP Measures".
(d) For entities not wholly-owned by us, includes our share, based on our ownership percentage, of the wellhead and throughput volumes and NGL production.

Three months ended September 30, 2017 vs. Three months ended September 30, 2016

Total Operating Revenues — Total operating revenues increased $232 million in 2017 compared to 2016 primarily as a result of the following:

- $272 million increase for our Logistics and Marketing segment primarily due to higher commodity prices and favorable commodity derivative activity, partially offset by lower gas and NGL sales volumes;

- $120 million increase for our Gathering and Processing segment primarily due to higher commodity prices, higher gas and NGL sales volumes primarily related to our North region which impact both sales and purchases. These increases were partially offset by lower gas and NGL sales volumes in the South, Midcontinent and Permian regions, unfavorable commodity derivative activity and the sale of our Douglas gathering system;

These increases were partially offset by:

- $160 million increase in inter-segment eliminations, which relate to sales of gas and NGL volumes from our Gathering and Processing segment to our Logistics and Marketing segment, primarily due to higher commodity prices, partially offset by lower gas and NGL sales volumes.

Total Purchases — Total purchases increased $258 million in 2017 compared to 2016 primarily as a result of the following:

- $266 million increase for our Logistics and Marketing segment for the reasons discussed above;

- $152 million increase for our Gathering and Processing segment for the reasons discussed above;

These increases were partially offset by:

- $160 million increase in inter-segment eliminations, which relate to sales of gas and NGL volumes from our Gathering and Processing segment to our Logistics and Marketing segment, primarily due to higher commodity prices, partially offset by lower gas and NGL sales volumes.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2017 compared to 2016 primarily as a result of increased asset reliability and planned maintenance spending associated with anticipated volume growth and investment in process improvements, partially offset by other cost savings initiatives and the sale of our Douglas system in June 2017.

General and Administrative Expense — General and administrative expense increased in 2017 compared to 2016 primarily as a result of investment in process and technology improvements.

Asset impairments — Asset impairments in 2017 represent the impairment of property, plant and equipment and intangible assets in our South region.

Other (Expense) Income — Other expense in 2016 represents the write-off of property, plant and equipment.

Interest Expense - Interest expense decreased in 2017 compared to 2016 as a result of lower average outstanding debt balances.

Restructuring Costs - Restructuring costs in 2016 related to our headcount reduction in April of 2016.

Gain on Sale of Assets, Net — The gain on sale in 2016 represents the sale of our Northern Louisiana system.

Net (Loss) Income Attributable to Partners — Net income attributable to partners decreased in 2017 compared to 2016 for the reasons discussed above.

Gross Margin — Gross margin decreased $26 million in 2017 compared to 2016 primarily as a result of the following:

- $32 million decrease for our Gathering and Processing segment primarily related to lower volumes across our South, Midcontinent, and Permian regions due to reduced drilling activity in prior periods, the impact of Hurricane Harvey primarily in the South and Permian regions, the sale of our Douglas gathering system and unfavorable commodity derivative activity. These decreases were partially offset by higher commodity prices, increased volume from growth projects in our North region, higher NGL recoveries in our North region and contract realignment efforts in our Permian region;

  These decreases were partially offset by:

- $6 million increase for our Logistics and Marketing segment primarily related to favorable commodity derivative activity and higher NGL and gas marketing margins, partially offset by a decrease in natural gas storage volumes.

Nine months ended September 30, 2017 vs. Nine months ended September 30, 2016

Total Operating Revenues — Total operating revenues increased $1,215 million in 2017 compared to 2016 primarily as a result of the following:

- $1,234 million increase for our Logistics and Marketing segment primarily due to increased commodity prices and favorable commodity derivative activity, partially offset by lower gas and NGL sales volumes and the sale of our Northern Louisiana System;

- $775 million increase for our Gathering and Processing segment primarily due to higher commodity prices, higher gas and NGL sales volumes primarily related to our North region which impacts both sales and purchases, and higher transportation, processing and other primarily related to fee based contract realignment efforts. These increases were partially offset by lower gas and NGL sales volumes in the South, Midcontinent and Permian regions, unfavorable commodity derivative activity and the sale of our Northern Louisiana system and Douglas gathering system;

  These increases were partially offset by:

- $794 million increase in inter-segment eliminations, which relate to sales of gas and NGL volumes from our Gathering and Processing segment to our Logistics and Marketing segment, primarily due to higher commodity prices, partially offset by lower gas and NGL sales volumes.

Total Purchases — Total purchases increased $1,073 million in 2017 compared to 2016 primarily as a result of the following:

- $1,221 million increase for our Logistics and Marketing segment for the reasons discussed above;

- $646 million increase for our Gathering and Processing segment for the reasons discussed above;

  These increases were partially offset by:

- $794 million increase in inter-segment eliminations, which relate to sales of gas and NGL volumes from our Gathering and Processing segment to our Logistics and Marketing segment, primarily due to higher commodity prices, partially offset by lower gas and NGL sales volumes.

General and Administrative Expense — General and administrative expense increased in 2017 compared to 2016 primarily as a result of investment in process and technology improvements.

Asset impairments — Asset impairments in 2017 represent the impairment of property, plant and equipment and intangible assets in our South region.

Other (Expense) Income — Other expense in 2017 primarily represents the write-off of property, plant and equipment associated with the expiration of a lease. Other income in 2016 primarily represents a producer settlement, net of legal fees, partially offset by the write-off of property, plant and equipment.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2017 compared to 2016 primarily as a result of the expansion and volume ramp up of the Sand Hills NGL pipeline in our Logistics and Marketing segment and an increase from Discovery in our Gathering and Processing segment primarily due to the accelerated recognition of previously deferred revenue associated with lower projections. We expect these projections to impact future earnings.

Interest Expense - Interest expense decreased in 2017 compared to 2016 as a result of lower average outstanding debt balances.

Restructuring Costs - Restructuring costs in 2016 related to our headcount reduction in April of 2016.

Gain on Sale of Assets, net — The gain on sale in 2017 represents the sale of our Douglas gathering system. The gain on sale in 2016 represents the sale of our Northern Louisiana system, partially offset by a loss on sale of non-core assets.

Net Income Attributable to Partners — Net income attributable to partners increased in 2017 compared to 2016 for the reasons discussed above.

Gross Margin — Gross margin increased $142 million in 2017 compared to 2016 primarily as a result of the following:

- $129 million increase for our Gathering and Processing segment primarily related to higher commodity prices, increased volume from growth projects, higher margins on a specific producer arrangement, higher NGL recoveries and a producer settlement in our North region, and contract realignment efforts in our Permian and Midcontinent regions. These increases were partially offset by lower volumes across our South, Midcontinent, and Permian regions due to reduced drilling activity in prior periods, the impact of Hurricane Harvey primarily in the South and Permian regions, the sale of our Northern Louisiana system, the sale of our Douglas gathering system and unfavorable commodity derivative activity; and

- $13 million increase for our Logistics and Marketing segment primarily related to favorable commodity derivative activity and higher NGL marketing margins, partially offset by lower margins on wholesale propane.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

Earnings from investments in unconsolidated affiliates were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Millions)			
DCP Sand Hills Pipeline, LLC	$ 37	$ 28	$ 105	$ 84
Discovery Producer Services LLC	14	20	59	52
DCP Southern Hills Pipeline, LLC	10	13	34	37
Front Range Pipeline LLC	5	5	12	14
Texas Express Pipeline LLC	4	2	7	6
Mont Belvieu Enterprise Fractionator	3	4	10	12
Mont Belvieu 1 Fractionator	2	2	6	7
Other	(1)	1	1	2
Total earnings from unconsolidated affiliates	$ 74	$ 75	$ 234	$ 214

Distributions received from investments in unconsolidated affiliates were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Millions)			
DCP Sand Hills Pipeline, LLC	$ 45	$ 39	$ 118	$ 107
Discovery Producer Services LLC	19	24	68	69
DCP Southern Hills Pipeline, LLC	16	15	47	45
Front Range Pipeline LLC	5	8	12	18
Texas Express Pipeline LLC	5	4	10	9
Mont Belvieu Enterprise Fractionator	2	4	8	15
Mont Belvieu 1 Fractionator	—	2	4	8
Other	1	2	3	3
Total distributions from unconsolidated affiliates	$ 93	$ 98	$ 270	$ 274

Results of Operations — Gathering and Processing Segment

Operating Data

				Three Months Ended September 30, 2017		Nine Months Ended September 30, 2017	
Regions	Plants	Approximate Gathering and Transmission Systems (Miles)	Approximate Net Nameplate Plant Capacity (MMcf/d) (a)	Natural Gas Wellhead Volume (MMcf/d) (a)	NGL Production (MBbls/d) (a)	Natural Gas Wellhead Volume (MMcf/d) (a)	NGL Production (MBbls/d) (a)
North	13	4,000	1,260	1,134	87	1,116	86
Permian	16	16,500	1,460	927	101	951	102
Midcontinent	12	29,000	1,765	1,206	95	1,199	90
South	20	7,500	3,295	1,193	93	1,242	87
Total	61	57,000	7,780	4,460	376	4,508	365

(a) Represents total capacity or total volumes allocated to our proportionate ownership share.

The results of operations for our Gathering and Processing segment are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2017 vs. 2016		Variance Nine Months 2017 vs. 2016	
	2017	2016	2017	2016	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)							
Operating revenues:								
Sales of natural gas, NGLs and condensate	$ 1,249	$ 1,066	$ 3,562	$ 2,781	$ 183	17 %	$ 781	28 %
Transportation, processing and other	145	146	424	418	(1)	(1)%	6	1 %
Trading and marketing (losses) gains, net	(57)	5	(21)	(9)	(62)	*	(12)	*
Total operating revenues	1,337	1,217	3,965	3,190	120	10 %	775	24 %
Purchases of natural gas and NGLs	(1,034)	(882)	(2,944)	(2,298)	152	17 %	646	28 %
Operating and maintenance expense	(154)	(146)	(469)	(458)	8	5 %	11	2 %
General and administrative expense	(2)	(2)	(15)	(10)	—	— %	5	50 %
Depreciation and amortization expense	(85)	(85)	(256)	(258)	—	— %	(2)	(1)%
Asset impairments	(48)	—	(48)	—	(48)	*	(48)	*
Other (expense) income, net	—	(13)	(3)	74	13	*	(77)	*
Earnings from unconsolidated affiliates (a)	15	20	59	52	(5)	(25)%	7	13 %
Gain on sale of assets, net	—	25	34	19	(25)	*	15	*
Segment net income	29	134	323	311	(105)	*	12	4 %
Segment net income attributable to noncontrolling interests	—	—	(1)	(1)	—	*	—	— %
Segment net income attributable to partners	$ 29	$ 134	$ 322	$ 310	$ (105)	*	$ 12	4 %
Other data:								
Segment gross margin (b)	$ 303	$ 335	$ 1,021	$ 892	$ (32)	(10)%	$ 129	14 %
Non-cash commodity derivative mark-to-market	$ (51)	$ (5)	$ (4)	$ (73)	$ (46)	*	$ 69	*
Natural gas wellhead (MMcf/d) (c)	4,460	5,005	4,508	5,230	(545)	(11)%	(722)	(14)%
NGL gross production (MBbls/d) (c)	376	392	365	401	(16)	(4)%	(36)	(9)%

* Percentage change is not meaningful.

(a) Earnings from unconsolidated affiliates includes 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.
(b) Segment gross margin consists of total operating revenues, less purchases of natural gas and NGLs. Please read “Reconciliation of Non-GAAP Measures”.
(c) For entities not wholly-owned by us, includes our share, based on our ownership percentage, of the wellhead and throughput volumes and NGL production.

Three months ended September 30, 2017 vs. Three months ended September 30, 2016

Total Operating Revenues — Total operating revenues increased $120 million in 2017 compared to 2016, primarily as a result of the following:

- $251 million increase attributable to higher commodity prices, which impacted both sales and purchases, before the impact of derivative activity;
- $36 million increase attributable to higher gas and NGL sales volumes primarily related to our DJ Basin system in our North region;

  These increases were partially offset by:

- $104 million decrease primarily as a result of lower volumes across our South, Midcontinent and Permian regions due to reduced drilling activity in prior periods;
- $62 million decrease as a result of commodity derivative activity attributable to an increase in unrealized commodity derivative losses of $46 million due to movements in forward prices of commodities, and a $16 million increase in realized cash settlement losses in 2017; and
- $1 million decrease in transportation, processing and other primarily related to the sale of our Douglas gathering system, partially offset by fee based contract realignment efforts in our Permian region.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased $152 million in 2017 compared to 2016 as a result of higher commodity prices and higher gas and NGL sales volumes in our North region, partially offset by decreased volumes in our South, Midcontinent and Permian regions.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2017 compared to 2016 primarily as a result of increased reliability spending and gathering pipeline remediation spending partially offset by cost savings initiatives and the sale of our Douglas gathering system in June 2017.

Asset impairments — Asset impairments in 2017 represent the impairment of property, plant and equipment and intangible assets in our South region.

Other (Expense) Income — Other expense in 2016 represents the write-off of property, plant and equipment.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates decreased in 2017 compared to 2016 primarily due to lower volumes at Discovery.

Gain on Sale of Assets, net — The gain on sale in 2016 primarily represents the sale of our Northern Louisiana system in our South Region.

Segment Gross Margin — Segment gross margin decreased $32 million in 2017 compared to 2016, primarily as a result of the following:

- $62 million decrease as a result of commodity derivative activity as discussed above;
- $22 million decrease primarily as a result of lower volumes across our South, Permian and Midcontinent regions due to reduced drilling activity in prior periods and the impact of Hurricane Harvey primarily related to the South and Permian regions, partially offset by fee based contract realignment efforts in the Permian region;

  These decreases were partially offset by:

- $46 million increase as a result of higher commodity prices; and
- $6 million increase as a result of increased volume from growth projects and higher NGL recoveries primarily related to our DJ Basin system in our North region, partially offset by the sale of our Douglas gathering system.

Total Wellhead — Natural gas wellhead decreased in 2017 compared to 2016 reflecting lower volumes primarily from (i) lower volumes associated with general declines within the South, Permian and Midcontinent regions, (ii) the sale of our Douglas gathering system within our North region, and (iii) the impact of Hurricane Harvey primarily related to the South and Permian regions, partially offset by general volume increases due to maximizing capacity utilization and growth projects within the North region.

NGL Gross Production — NGL production decreased in 2017 compared to 2016 primarily as a result of (i) lower volumes associated with general declines within the South, Permian and Midcontinent regions, (ii) the sale of our Douglas gathering system within our North region and (iii) the impact of Hurricane Harvey primarily related to the South and Permian regions, partially offset by general volume increases due to maximizing capacity utilization within the North region.

Nine Months Ended September 30, 2017 vs. Nine Months Ended September 30, 2016

Total Operating Revenues — Total operating revenues increased $775 million in 2017 compared to 2016, primarily as a result of the following:

- $1,076 million increase attributable to higher commodity prices, which impacted both sales and purchases, before the impact of derivative activity;
- $70 million increase attributable to higher gas and NGL sales volumes and the impact of a specific producer arrangement primarily related to our DJ Basin system in our North region;
- $6 million increase in transportation, processing and other primarily related to fee based contract realignment efforts, partially offset by lower volumes in the South region and the sale of our Northern Louisiana system and Douglas gathering system;

  These increases were partially offset by:

- $365 million decrease primarily as a result of lower volumes across our South, Midcontinent and Permian regions due to reduced drilling activity in prior periods and the impact of Hurricane Harvey primarily related to the South and Permian regions; and
- $12 million decrease as a result of commodity derivative activity attributable to a $81 million increase in realized cash settlement losses, partially offset by a decrease in unrealized commodity derivative losses of $69 million due to movements in forward prices of commodities in 2017.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased $646 million in 2017 compared to 2016 as a result of higher commodity prices and higher gas and NGL sales volumes in our North region, partially offset by decreased volumes in our South, Midcontinent and Permian regions.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2017 compared to 2016 primarily as a result of increased reliability spending and planned maintenance spending associated with anticipated volume growth partially offset by cost savings initiatives and the sale of our Northern Louisiana system in July 2016 and Douglas gathering system in June 2017.

General and Administrative Expense — General and administrative expense increased in 2017 compared to 2016 primarily as a result of investment in process improvements.

Asset impairments — Asset impairments in 2017 represent the impairment of property, plant and equipment and intangible assets in our South region.

Other (Expense) Income — Other expense in 2017 represents the write-off of property, plant and equipment. Other income in 2016 represents a producer settlement, net of legal fees partially offset by the write-off of property, plant and equipment.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2017 compared to 2016 primarily due to the accelerated recognition of previously deferred revenue associated with lower projections at Discovery. We expect these projections to impact future earnings.

Gain on sale of assets, net - The gain on sale in 2017 represents the sale of our Douglas gathering system. The gain on sale in 2016 represents the sale of our Northern Louisiana system partially offset by a loss on sale of non-core assets.

Segment Gross Margin — Segment gross margin increased $129 million in 2017 compared to 2016, primarily as a result of the following:

- $194 million increase as a result of higher commodity prices;

- $31 million increase as a result of increased volume from growth projects, higher margins on a specific producer arrangement, and higher NGL recoveries primarily related to our DJ Basin system and a producer settlement in our North region;

  These increases were partially offset by:

- $71 million decrease primarily as a result of lower volumes across our South, Midcontinent and Permian regions due to reduced drilling activity in prior periods, partially offset by fee based contract realignment efforts in the Permian and Midcontinent region;

- $13 million decrease as a result of the sale of our Northern Louisiana system in our South region and Douglas gathering system in our North region; and

- $12 million decrease as a result of commodity derivative activity as discussed above.

Total Wellhead — Natural gas wellhead decreased in 2017 compared to 2016 reflecting lower volumes primarily from (i) lower volumes associated with general declines within the South, Permian and Midcontinent regions (ii) the sale of our Northern Louisiana system within our South region and (iii) the sale of our Douglas gathering system within our North region and (iv) the impact of Hurricane Harvey primarily related to the South and Permian regions, partially offset by (v) general volume increases due to maximizing capacity utilization and growth projects within the North region.

NGL Gross Production — NGL production decreased in 2017 compared to 2016 primarily as a result of (i) lower volumes associated with general declines within the South, Permian and Midcontinent regions, (ii) the sale of our Northern Louisiana system within our South region and (iii) the sale of our Douglas gathering system within our North region and (iv) the impact of Hurricane Harvey primarily related to the South and Permian regions, partially offset by (v) general volume increases due to maximizing capacity utilization within the North region.

Results of Operations — Logistics and Marketing Segment

NGL Pipeline and Fractionator Operating Data

System	Approximate System Length (Miles)	Fractionators	Approximate Throughput Capacity (MBbls/d) (a)	Three Months Ended September 30, 2017		Nine Months Ended September 30, 2017	
				Pipeline Throughput (MBbls/d) (a)	Fractionator Throughput (MBbls/d) (a)	Pipeline Throughput (MBbls/d) (a)	Fractionator Throughput (MBbls/d) (a)
Sand Hills pipeline	1,300	—	190	193	—	181	—
Southern Hills pipeline	950	—	117	65	—	67	—
Front Range pipeline	450	—	50	36	—	36	—
Texas Express pipeline	600	—	28	16	—	15	—
Other NGL Pipelines (b)	1,200	—	172	152	—	148	—
Mont Belvieu fractionators	—	2	60	—	49	—	48
Total	4,500	2	617	462	49	447	48

(a) Represents total capacity or total volumes allocated to our proportionate ownership share.
(b) Excludes other natural gas pipelines within our Logistics and Marketing segment.

The results of operations for our Logistics and Marketing segment are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2017 vs. 2016		Variance Nine Months 2017 vs. 2016	
	2017	2016	2017	2016	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)							
Operating revenues:								
Sales of natural gas and NGLs	$ 1,882	$ 1,614	$ 5,515	$ 4,290	$ 268	17 %	$ 1,225	29 %
Transportation, processing and other	17	17	50	53	—	— %	(3)	(6)%
Trading and marketing gains, net	14	10	31	19	4	40 %	12	63 %
Total operating revenues	1,913	1,641	5,596	4,362	272	17 %	1,234	28 %
Purchases of natural gas and NGLs	(1,856)	(1,590)	(5,431)	(4,210)	266	17 %	1,221	29 %
Operating and maintenance expense	(9)	(13)	(31)	(33)	(4)	(31)%	(2)	(6)%
General and administrative expense	(3)	(2)	(8)	(7)	1	(50)%	1	14 %
Depreciation and amortization expense	(4)	(4)	(11)	(12)	—	— %	(1)	(8)%
Other expense	(1)	—	(12)	(5)	1	*	7	*
Earnings from unconsolidated affiliates (a)	59	55	175	162	4	7 %	13	8 %
Gain on sale of assets, net	—	16	—	16	(16)	*	(16)	*
Segment net income attributable to partners	$ 99	$ 103	$ 278	$ 273	$ (4)	(4)%	$ 5	2 %
Other data:								
Segment gross margin (b)	$ 57	$ 51	$ 165	$ 152	$ 6	12 %	$ 13	9 %
Non-cash commodity derivative mark-to-market	$ (8)	$ 14	$ 5	$ (7)	(22)	*	12	*
NGL pipelines throughput (MBbls/d) (c)	462	434	447	421	28	6 %	26	6 %

(a) Earnings from unconsolidated affiliates 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) Segment gross margin consists of total operating revenues less purchases of natural gas and NGLs. Please read “Reconciliation of Non-GAAP Measures”.

(c) For entities not wholly-owned by us, includes our share, based on our ownership percentage, of the wellhead and throughput volumes and NGL production.

Three months ended September 30, 2017 vs. Three months ended September 30, 2016

Total Operating Revenues — Total operating revenues increased $272 million in 2017 compared to 2016, primarily as a result of the following:

- $387 million increase as a result of higher commodity prices, which impacted both sales and purchases, before the impact of derivative activity;
- $4 million increase as a result of commodity derivative activity attributable to a $26 million increase in realized cash settlement gains in 2017, partially offset by an increase in unrealized commodity derivative losses of $22 million due to movements in forward prices of commodities;

These increases were partially offset by:

- $119 million decrease attributable to lower gas and NGL sales volumes, which impacted both sales and purchases.

Purchases of NGLs — Purchases of NGLs increased $266 million in 2017 compared to 2016, primarily as a result of higher commodity prices, partially offset by lower gas and NGL sales volumes.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2017 compared to 2016 primarily as a result of timing of planned maintenance spending.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2017 compared to 2016 primarily as a result of higher throughput volumes on Sand Hills due to the capacity expansion in 2017, partially offset by the impact of Hurricane Harvey primarily related to the Sand Hills and Southern Hills pipelines and the Mont Belvieu fractionators.

Gain on sale of assets, net — The gain on sale in 2016 primarily represents the sale of our Northern Louisiana system.

Segment Gross Margin — Segment gross margin increased $6 million in 2017 compared to 2016 primarily as a result of the following:

- $4 million increase as a result of commodity derivative activity as discussed above;
- $7 million increase as a result of higher NGL and gas marketing margins;

These increases are partially offset by:

- $5 million decrease in natural gas storage volumes.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2017 compared to 2016 primarily as a result of higher throughput volumes on Sand Hills due to the capacity expansion in 2017, partially offset by the impact of Hurricane Harvey primarily related to the Sand Hills and Southern Hills pipelines.

Nine Months Ended September 30, 2017 vs. Nine Months Ended September 30, 2016

Total Operating Revenues — Total operating revenues increased $1,234 million in 2017 compared to 2016, primarily as a result of the following:

- $1,565 million increase as a result of higher commodity prices, which impacted both sales and purchases, before the impact of derivative activity;
- $12 million increase as a result of commodity derivative activity attributable to an increase in unrealized commodity derivative gains of $12 million due to movements in forward prices of commodities in 2017;

These increases were partially offset by:

- $307 million decrease attributable to lower gas and NGL sales volumes, which impacted both sales and purchases, and;
- $36 million decrease due to the sale of our Northern Louisiana system.

Purchases of NGLs — Purchases of NGLs increased $1,221 million in 2017 compared to 2016, primarily as a result of higher commodity prices, partially offset by lower gas and NGL sales volumes.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2017 compared to 2016 primarily as a result of the timing of planned maintenance spending.

Other expense — Other expense in 2017 primarily represents the write-off of property, plant and equipment associated with the expiration of a lease while other expense in 2016 primarily represents the write-off of property, plant and equipment and other long term assets.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2017 compared to 2016 primarily as a result of higher throughput volumes on Sand Hills due to the capacity expansion in the second quarter of 2016, partially offset by the impact of Hurricane Harvey primarily related to the Sand Hills and Southern Hills pipelines and the Mont Belvieu fractionators.

Gain on sale of assets, net — The gain on sale in 2016 primarily represents the sale of our Northern Louisiana system.

Segment Gross Margin — Segment gross margin increased $13 million in 2017 compared to 2016, primarily as a result of the following:

- $12 million increase as a result of commodity derivative activity discussed above;
- $9 million increase as a result of higher NGL marketing margins;

  These increases are partially offset by:

- $8 million of lower margins on wholesale propane.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2017 compared to 2016 primarily as a result of higher throughput volumes on Sand Hills due to the capacity expansion in the second quarter of 2016, partially offset by the impact of Hurricane Harvey primarily related to the Sand Hills and Southern Hills pipelines.

Liquidity and Capital Resources

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from our unconsolidated affiliates;
- borrowings under our Credit Agreement;
- proceeds from asset rationalization;
- reduction of incentive distribution right payments;
- debt offerings;
- issuances of additional common units or other securities;
- 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;
- payments to service our debt;
- growth capital expenditures;
- contributions to our unconsolidated affiliates to finance our share of their capital expenditures;
- business and asset acquisitions; 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.

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.

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 Credit Agreement and the indentures governing our notes.

In February 2017, we further amended our Credit Agreement to increase the aggregate commitments under the unsecured revolving credit facility to approximately $1.4 billion. The Credit Agreement is used for working capital requirements and other general partnership purposes including acquisitions.

As of September 30, 2017, there were no outstanding borrowings on the revolving credit facility under the Credit Agreement. We had unused borrowing capacity of $1,373 million, net of $25 million of letters of credit, under the Credit Agreement. The financial covenants set forth in the Credit Agreement limit the Partnership's ability to incur incremental debt by $1,373 million as of September 30, 2017. Our cost of borrowing under the Credit Agreement is determined by a ratings-based pricing grid. In the first quarter of 2017, our credit rating was lowered. As a result of this action, interest rates on outstanding borrowings under the Credit Agreement increased. As of November 2, 2017, we had no outstanding borrowings on the revolving credit facility and had approximately $1,373 million, net of $26 million of letters of credit, of unused borrowing capacity under the Credit Agreement. We used a portion of the cash received from the Transaction to repay outstanding debt on our revolving credit facility.

On January 1, 2017, DCP Midstream, LLC contributed to us: (i) its ownership interests in all of its subsidiaries owning operating assets, and (ii) $424 million of cash. In consideration of the Partnership's receipt of the Contributions, (i) the Partnership issued 28,552,480 common units to DCP Midstream, LLC and 2,550,644 general partner units to DCP Midstream GP, LP, the General Partner, in a private placement, and (ii) the Operating Partnership assumed $3,150 million of DCP Midstream, LLC's debt. The incentive distributions payable to the holders of the Partnership's incentive distribution rights with respect to the fiscal years 2017, 2018 and 2019, in certain circumstances, may be reduced in an amount up to $100 million per fiscal year as necessary to provide that the Distributable Cash Flow of the Partnership (as adjusted) during such year meets or exceeds the amount of distributions made by the Partnership (as adjusted) to the partners of the Partnership with respect to such year.

In April 2015, we filed a shelf registration statement with the SEC, that became effective upon filing, which 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.

In August 2017, we filed a shelf registration statement with the SEC which allows us to issue up to $750 million in common units pursuant to our 2014 equity distribution agreement to replace the expired shelf registration statement. During the nine months ended September 30, 2017, we issued no common units pursuant to these registration statements.

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 the first quarter of 2019 with fixed price commodity swaps. For additional information regarding our derivative activities, please read Item 3. "Quantitative and Qualitative Disclosures about Market Risk" contained herein.

When we enter into commodity swap 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, cash collateral we may be required to post with counterparties to our commodity derivative instruments, borrowings of and payments on debt, capital expenditures, and increases or decreases in other long-term assets. We expect that our future working capital requirements will be impacted by these same recurring factors.

We had working capital deficits of $473 million and $629 million as of September 30, 2017 and December 31, 2016, respectively. The change in working capital is primarily attributable to the cash received in the Transaction offset by the repayment of long-term debt outstanding on the revolving credit facility. We had a net derivative working capital deficit of $10 million and $49 million as of September 30, 2017 and December 31, 2016, respectively.

As of September 30, 2017, we had $312 million in cash and cash equivalents, of which $1 million was held by consolidated subsidiaries we did not wholly own.

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

	Nine Months Ended September 30,	
	2017	2016
	(Millions)	
Net cash provided by operating activities	$ 684	$ 521
Net cash (used in) provided by investing activities	$ (198)	$ 9
Net cash used in financing activities	$ (175)	$ (518)

Nine Months Ended September 30, 2017 vs. Nine Months Ended September 30, 2016

Operating Activities — The changes in net cash provided by operating activities are attributable to our net income adjusted for non-cash charges and changes in working capital as presented in the condensed consolidated statements of cash flows.

We received cash distributions in excess of earnings from unconsolidated affiliates of $36 million and $60 million during the nine months ended September 30, 2017 and 2016, respectively. For additional information regarding fluctuations in our earnings from unconsolidated affiliates, please read "Results of Operations".

Investing Activities — Net cash used in investing activities increased $207 million in 2017 compared to the same period in 2016 primarily as a result of the following:

Net cash used in investing activities during the nine months ended September 30, 2017 was comprised of capital expenditures of $258 million, primarily for (1) expansion capital expenditures including construction of the Mewbourn 3 plant, and (2) investment in unconsolidated affiliates, net of $70 million for the capacity expansion of the Sand Hills pipeline, partially offset by (3) proceeds from the sale of our Douglas gathering system of $130 million.

Net cash provided by investing activities during the nine months ended September 30, 2016 was comprised of: (1) capital expenditures of $113 million, which generally consisted of maintenance capital expenditures for our existing facilities and expansion capital expenditures for construction of additional gathering systems, processing plants, fractionators and other facilities and infrastructure and well connections; (2) investment in unconsolidated affiliates, net of $38 million, which were partially offset by (3) proceeds from the sale of our Northern Louisiana system of $160 million.

Financing Activities — Net cash used in financing activities decreased $343 million in 2017 compared to the same period in 2016 primarily as a result of the following:

Net cash used in financing activities during the nine months ended September 30, 2017 was primarily comprised of: (1) payment of debt outstanding on the revolving credit facility of $195 million from cash received from the Transaction, (2) distributions paid to limited partners and the general partner of $390 million, (3) distributions to noncontrolling interests of $6 million, and (4) payment of deferred financing costs of $2 million; which were partially offset by (5) cash received from the Transaction of $418 million.

Net cash used in financing activities during the nine months ended September 30, 2016 was primarily comprised of: (1) payment of long-term debt of $3,216 million, (2) distributions paid to limited partners and the general partner of $362 million, (3) distributions to noncontrolling interests of $6 million, and (4) payment of deferred financing costs of $10 million; which were partially offset by (5) proceeds from long-term debt of $2,926 million and (6) $150 million attributable to the net change in advances to our predecessor operations from DCP Midstream, LLC as a result of the Transaction.

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 $100 million and $145 million, and approved expansion capital expenditures of between $325 million and $375 million, for the year ending December 31, 2017. We forecast maintenance spending to be at the low end of the range, and expansion spending to approach the high end of the range. Expansion capital expenditures include the construction of the Mewbourn 3 plant, Grand Parkway Phase 2 and O'Connor bypass in our DJ Basin system, and the capacity expansions of the Sand Hills pipeline, which are shown as an investment in unconsolidated affiliates in our condensed consolidated statements of cash flows.

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

	Nine Months Ended September 30, 2017			Nine Months Ended September 30, 2016		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(Millions)					
Our portion	$ 64	$ 191	$ 255	$ 61	$ 53	$ 114
Noncontrolling interest portion and reimbursable projects (a)	1	2	3	1	(2)	(1)
Total	$ 65	$ 193	$ 258	$ 62	$ 51	$ 113

(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 $70 million and $38 million during the nine months ended September 30, 2017 and 2016, 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, to fund future acquisitions and capital expenditures.

We expect to fund future capital expenditures with funds generated from our operations, borrowings under our Credit Agreement, the issuance of additional limited partnership units and the issuance of long-term debt.

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 $390 million and $362 million during the nine months ended September 30, 2017 and 2016, 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.

As part of the Transaction, Phillips 66 and Enbridge agreed, if required, to provide a reduction to incentive distributions payable to our General Partner under our Partnership Agreement of up to $100 million annually through 2019 to target an approximate 1.0 times distribution coverage ratio. Under the terms of our amended partnership agreement, the amount of incentive distributions paid to our General Partner will be evaluated by our General Partner on both a quarterly and annual basis and may be reduced each quarter by an amount determined by our general partner (the “IDR giveback”). If no determination is made by our General Partner, the quarterly IDR giveback will be $20 million. The IDR giveback, of up to $100 million annually, will be subject to a true-up at the end of the year by taking our total distributable cash flow (as adjusted under our amended partnership agreement) less the total annual distribution payable to our unitholders, adjusted to target an approximate

1.0 times coverage ratio. In accordance with our amended partnership agreement, distributions declared were $155 million and $424 million for the three and nine months ended September 30, 2017, respectively. Distributions declared reflected no IDR givebacks in the three months ended September 30, 2017, and reflected $40 million of IDR givebacks for the nine months ended September 30, 2017.

We expect to continue to use cash provided by operating activities for the payment of distributions to our unitholders and general partner. See Note 13. "Partnership Equity and Distributions" in the Notes to Condensed Consolidated Financial Statements in Item 1. “Financial Statements.”

Total Contractual Cash Obligations

A summary of our total contractual cash obligations as of September 30, 2017, was as follows:

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
	(Millions)				
Debt (a)	$ 8,354	$ 780	$ 1,832	$ 1,205	$ 4,537
Operating lease obligations	179	43	66	40	30
Purchase obligations (b)	2,782	750	758	659	615
Other long-term liabilities (c)	141	—	16	15	110
Total	$ 11,456	$ 1,573	$ 2,672	$ 1,919	$ 5,292

(a) Includes interest payments on debt securities that have been issued. These interest payments are $280 million, $457 million, $355 million, and $2,037 million for less than one year, one to three years, three to five years, and thereafter, respectively.

(b) 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 commodities in future periods and other items, including long-term fractionation agreements. 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 September 30, 2017. Purchase obligations exclude accounts payable, accrued taxes 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 sheets, 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.

(c) Other long-term liabilities include asset retirement obligations, long-term environmental remediation liabilities, gas purchase liabilities, and other miscellaneous liabilities recognized in the September 30, 2017 condensed consolidated balance sheet. The table above excludes non-cash obligations as well as $28 million of Executive Deferred Compensation Plan contributions and $11 million of long-term incentive plans as the amount and timing of any payments are not subject to reasonable estimation.

Off-Balance Sheet Obligations

As of September 30, 2017, we had no items that were classified as off-balance sheet obligations.

Reconciliation of Non-GAAP Measures

Gross Margin and Segment Gross Margin — In addition to net income, 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, less purchases of natural gas and NGLs, and we define segment gross margin for each segment as total operating revenues 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 adjusted for (i) distributions from unconsolidated affiliates, net of earnings (ii) depreciation and amortization expense, (iii) net interest expense, (iv) noncontrolling interest in depreciation and income tax expense, (v) unrealized gains and losses from commodity derivatives (vi) income tax expense or benefit, (vii) impairment expense and (viii) certain other non-cash items. Adjusted EBITDA further excludes items of income or loss that we characterize as unrepresentative of our ongoing operations. Management believes these measures provide investors meaningful insight into results from ongoing operations.

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 adjusted for (i) distributions from unconsolidated affiliates, net of earnings (ii) depreciation and amortization expense, (iii) net interest expense, (iv) noncontrolling interest in depreciation and income tax expense, (v) unrealized gains and losses from commodity derivatives (vi) income tax expense or benefit, (vii) impairment expense and (viii) certain other non-cash items. Adjusted EBITDA further excludes items of income or loss that we characterize as unrepresentative of our ongoing operations 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.

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 accompanying schedules provide reconciliations of gross margin, segment gross margin and adjusted segment EBITDA to their most directly comparable GAAP financial measures.

Distributable Cash Flow — We define Distributable Cash Flow as adjusted EBITDA, as defined above, less maintenance capital expenditures, net of reimbursable projects, less interest expense and certain other items. 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. We compare the Distributable Cash Flow we generate to the cash distributions we expect to pay our partners. Using this metric, we compute our distribution coverage ratio. 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.

The following table sets forth our reconciliation of certain non-GAAP measures:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Reconciliation of Non-GAAP Measures	(Millions)			
Reconciliation of net (loss) income attributable to partners to gross margin:				
Net (loss) income attributable to partners	$ (20)	$ 89	$ 169	$ 132
Interest expense	73	77	219	235
Income tax expense	2	1	5	6
Operating and maintenance expense	168	161	513	506
Depreciation and amortization expense	94	94	282	284
General and administrative expense	69	64	202	187
Asset impairments	48	—	48	—
Other expense (income), net	—	14	15	(68)
Restructuring costs	—	2	—	10
Earnings from unconsolidated affiliates	(74)	(75)	(234)	(214)
Gain on sale of assets, net	—	(41)	(34)	(35)
Net income attributable to noncontrolling interests	—	—	1	1
Gross margin	$ 360	$ 386	$ 1,186	$ 1,044
Non-cash commodity derivative mark-to-market (a)	$ (59)	$ 9	$ 1	$ (80)
Reconciliation of segment net income attributable to partners to segment gross margin:				
Gathering and Processing segment:				
Segment net income attributable to partners	$ 29	$ 134	$ 322	$ 310
Operating and maintenance expense	154	146	469	458
Depreciation and amortization expense	85	85	256	258
General and administrative expense	2	2	15	10
Asset impairments	48	—	48	—
Other expense (income), net	—	13	3	(74)
Earnings from unconsolidated affiliates	(15)	(20)	(59)	(52)
Gain on sale of assets, net	—	(25)	(34)	(19)
Net income attributable to noncontrolling interests	—	—	1	1
Segment gross margin	$ 303	$ 335	$ 1,021	$ 892
Non-cash commodity derivative mark-to-market (a)	$ (51)	$ (5)	$ (4)	$ (73)
Logistics and Marketing segment:				
Segment net income attributable to partners	$ 99	$ 103	$ 278	$ 273
Operating and maintenance expense	9	13	31	33
Depreciation and amortization expense	4	4	11	12
Other expense, net	1	—	12	5
General and administrative expense	3	2	8	7
Earnings from unconsolidated affiliates	(59)	(55)	(175)	(162)
Gain on sale of assets, net	—	(16)	—	(16)
Segment gross margin	$ 57	$ 51	$ 165	$ 152
Non-cash commodity derivative mark-to-market (a)	$ (8)	$ 14	$ 5	$ (7)

(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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Millions)			
Reconciliation of net income attributable to partners to adjusted segment EBITDA:				
Gathering and Processing segment:				
Segment net income attributable to partners (a)	$ 29	$ 134	$ 322	$ 310
Non-cash commodity derivative mark-to-market	51	5	4	73
Depreciation and amortization expense, net of noncontrolling interest	85	85	256	258
Asset impairments	48	—	48	—
Gain on sale of assets, net	—	(25)	(34)	(19)
Distributions from unconsolidated affiliates, net of earnings	6	5	10	18
Other expense	1	13	4	13
Adjusted segment EBITDA	$ 220	$ 217	$ 610	$ 653
Logistics and Marketing segment:				
Segment net income attributable to partners	$ 99	$ 103	$ 278	$ 273
Non-cash commodity derivative mark-to-market	8	(14)	(5)	7
Depreciation and amortization expense, net of noncontrolling interest	4	4	11	12
Distributions from unconsolidated affiliates, net of earnings	13	18	26	42
Gain on sale of assets, net	—	(16)	—	(16)
Other expense	—	—	9	—
Adjusted segment EBITDA	$ 124	$ 95	$ 319	$ 318

(a) There were no lower of cost or market adjustments for the three and nine months ended September 30, 2017. There were no lower of cost or market adjustments for the three months ended September 30, 2016 and $3 million for the nine months ended September 30, 2016.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Critical Accounting Policies and Estimates within exhibit 99.3 "Management's Discussion and Analysis of Financial Condition and Results of Operations" to the May 2017 8-K and Note 2 of the Notes to Consolidated Financial Statements in Exhibit 99.4 “Financial Statements and Supplementary Data” included as Exhibit 99.4 in the May 2017 8-K. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the nine months ended September 30, 2017 are the same as those described in the May 2017 8-K. 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 the May 2017 8-K.

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, 2016.

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 and processing operations. Our positions as of November 2, 2017 were as follows:

Commodity Swaps

Period	Commodity	Notional Volume - Short Positions	Reference Price	Price Range
October 2017 — December 2017	Natural Gas	(60,000) MMBtu/d	NYMEX Final Settlement Price (b)	$3.28-$4.27/MMBtu
January 2018 — March 2018	Natural Gas	(27,500) MMBtu/d	NYMEX Final Settlement Price (b)	$3.54-$3.68/MMBtu
October 2017 — December 2017	NGLs	(29,355) Bbls/d (d)	Mt.Belvieu (c)	$.28-$1.22/Gal
January 2018 — December 2018	NGLs	(15,591) Bbls/d (d)	Mt.Belvieu (c)	$.29-$.96/Gal
October 2017 — December 2017	Crude Oil	(3,001) Bbls/d (d)	NYMEX crude oil futures (a)	$53.54-$56.76/Bbl
January 2018 — December 2018	Crude Oil	(4,282) Bbls/d (d)	NYMEX crude oil futures (a)	$51.20-$56.61/Bbl
January 2019 — February 2019	Crude Oil	(2,560) Bbls/d (d)	NYMEX crude oil futures (a)	$51.26-$51.29/Bbl

(a) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract.
(b) NYMEX final settlement price for natural gas futures contracts.
(c) The average monthly OPIS price for Mt. Belvieu TET/Non-TET.
(d) Average Bbls/d per time period.

Our sensitivities for 2017 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 2017, and exclude the impact of non-cash mark-to-market changes 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 condensate, natural gas and NGL volumes that are currently unhedged.

Commodity Sensitivities Net of Cash Flow Protection Activities

	Per Unit Decrease		Unit of Measurement	Estimated Decrease in Annual Net Income Attributable to Partners	
				(Millions)	
Natural gas prices	$	0.10	MMBtu	$	7
Crude oil prices	$	1.00	Barrel	$	4
NGL prices	$	0.01	Gallon	$	5

In addition to the linear relationships in our commodity sensitivities above, additional factors may 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-proceeds and percentage-of-liquids processing arrangements that contain minimum fee clauses in which our processing margins convert to fee-based arrangements as commodity 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.

We estimate the following sensitivities related to the non-cash mark-to-market on our commodity derivatives associated with our open position on 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	$	3

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 the first quarter of 2018.

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 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 inventory within our natural gas storage operations as of September 30, 2017:

Inventory

Period ended	Commodity	Notional Volume - Long Positions		Fair Value (millions)		Weighted Average Price
September 30 2017	Natural Gas	11,055,842	MMBtu	$	32	$2.88/MMBtu

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions		Fair Value (millions)		Price Range
October 2017-April 2018	Natural Gas	(25,937,500)	MMBtu	$	2	$2.86-$3.58/MMBtu
October 2017-October 2018	Natural Gas	14,585,000	MMBtu	$	1	$2.69-$3.00/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, or the Exchange Act, is recorded, processed, summarized and reported within the time periods specified by the SEC’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 September 30, 2017, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of September 30, 2017, 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 quarter ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

The information provided in “Commitments and Contingent Liabilities,” included in Note 19 in the 2016 audited consolidated financial statements and notes thereto included as Exhibit 99.4 in the May 2017 8-K and in Note 15 of Part I of this Quarterly Report on Form 10-Q is incorporated by reference.

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, 2016. An investment in our securities involves various risks. When considering an investment in us, you should consider carefully all of the risk factors described in our Annual Report on Form 10-K for the year ended December 31, 2016. There are no material changes to the risk factors described in our Annual Report on Form 10-K for the year ended December 31, 2016.

Item 6. Exhibits

Exhibit Number		Description
2.1	*#	Contribution Agreement, dated December 30, 2016, by and among DCP Midstream, LLC, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
3.1	*	Certificate of Limited Partnership of DCP Midstream Partners, LP dated August 5, 2005 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on September 16, 2005).
3.2	*	Certificate of Amendment to Certificate of Limited Partnership of DCP Midstream Partners, LP dated January 11, 2017 (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 January 17, 2017).
3.3	*	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).
3.4	*	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).
3.5	*	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).
3.6	*	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated January 1, 2017 (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 January 6, 2017).
3.7	*	Amendment No. 4 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP dated January 11, 2017 (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 January 17, 2017).
10.1	*	Services and Employee Secondment Agreement, dated January 1, 2017, by and betweeen DCP Services, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's current report on Form 8-K (File No. 001 32678) filed with the SEC on January 6, 2017).
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, LP for the three and nine months ended September 30, 2017, 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.

\# Pursuant to Item 601(b)(2) of Regulation S-K, the Partnership agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DCP Midstream, LP

By: DCP Midstream GP, LP
its General Partner

By: DCP Midstream GP, LLC
its General Partner

Date: November 7, 2017

By: /s/ Wouter T. van Kempen
Name: Wouter T. van Kempen
Title: President and Chief Executive Officer
(Principal Executive Officer)

Date: November 7, 2017

By: /s/ Sean P. O'Brien
Name: Sean P. O'Brien
Title: Group Vice President and Chief Financial Officer
(Principal Financial Officer)

DCP Midstream, LP
Computation of Ratio of Earnings to Fixed Charges

The table below sets forth the computation of Ratios of Earnings to Fixed Charges:

	Nine Months Ended September 30,	Year Ended December 31,				
	2017	2016 (a)	2015 (a)	2014 (a)	2013 (a)	2012 (a)
	(Millions)					
Earnings from continuing operations before fixed charges:						
Pretax income from continuing operations attributable to partners before earnings from unconsolidated affiliates	$ (60)	$ (148)	$ (1,157)	$ 476	$ 554	$ 546
Fixed charges	224	324	355	322	290	274
Amortization of capitalized interest	5	7	7	6	5	4
Distributed earnings from unconsolidated affiliates	234	282	184	82	35	34
Less:						
Capitalized interest	(4)	(1)	(32)	(34)	(40)	(79)
Earnings from continuing operations before fixed charges	$ 399	$ 464	$ (643)	$ 852	$ 844	$ 779
Fixed charges:						
Interest expense, net of capitalized interest	213	300	310	277	239	185
Capitalized interest	4	1	32	34	40	79
Estimate of interest within rental expense	1	2	2	1	2	2
Amortization of deferred loan costs	6	21	11	10	9	8
Total fixed charges	$ 224	$ 324	$ 355	$ 322	$ 290	$ 274
Ratio of earnings to fixed charges (b)	1.78	1.43	—	2.65	2.91	2.84

(a) The financial information for the the years ended December 31, 2016, 2015, 2014, 2013 and 2012 includes the results of The DCP Midstream Business, which we acquired from DCP Midstream, LLC on January 1, 2017. 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 were retrospectively adjusted to furnish comparative information similar to the pooling method.

(b) Earnings for the year ended December 31, 2015 were inadequate to cover fixed charges by $998 million.

For purposes of determining the ratio of earnings to fixed charges, earnings are defined as pretax income or loss from continuing operations attributable to partners before earnings from unconsolidated affiliates, plus fixed charges, plus amortization of capitalized interest, plus distributed earnings from unconsolidated affiliates, less capitalized interest. Fixed charges consist of interest expense, capitalized interest, amortization of deferred loan costs, and an estimate of the interest within rental expense.

Exhibit 31.1

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Wouter T. van Kempen, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream, LP for the nine months ended September 30, 2017;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 7, 2017

/s/ Wouter T. van Kempen

Wouter T. van Kempen
President and Chief Executive Officer
(Principal Executive Officer)
DCP Midstream GP, LLC, general partner of
DCP Midstream GP, LP, general partner of
DCP Midstream, LP

Exhibit 31.2

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Sean P. O'Brien, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream, LP for the nine months ended September 30, 2017;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 7, 2017

/s/ Sean P. O'Brien

Sean P. O'Brien
Group Vice President and Chief Financial Officer
(Principal Financial Officer)
DCP Midstream GP, LLC, general partner of
DCP Midstream GP, LP, general partner of
DCP Midstream, LP

Exhibit 32.1

Certification of President and Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906
of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

The undersigned, the President and Chief Executive Officer of DCP Midstream GP, LLC, general partner of DCP Midstream GP, LP, general partner of DCP Midstream, LP (the "Partnership"), hereby certifies that, to his knowledge on the date hereof:

(a) the quarterly report on Form 10-Q of the Partnership for the nine months ended September 30, 2017, filed on the date hereof with the Securities and Exchange Commission (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Wouter T. van Kempen

Wouter T. van Kempen
President and Chief Executive Officer
(Principal Executive Officer)
November 7, 2017

A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Certification of Group Vice President and Chief Financial Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906
of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

The undersigned, the Group Vice President and Chief Financial Officer of DCP Midstream GP, LLC, general partner of DCP Midstream GP, LP, general partner of DCP Midstream, LP (the “Partnership”), hereby certifies that, to his knowledge on the date hereof:

(a) the quarterly report on Form 10-Q of the Partnership for the nine months ended September 30, 2017, filed on the date hereof with the Securities and Exchange Commission (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Sean P. O'Brien
Sean P. O'Brien
Group Vice President and Chief Financial Officer
(Principal Financial Officer)
November 7, 2017

A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.