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, 2018
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)**

(303) 595-3331

(Registrant's telephone number, including area code)

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	☐	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 1, 2018, there were 143,317,328 common units representing limited partner interests outstanding.

DCP MIDSTREAM, LP
FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2018

TABLE OF CONTENTS

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 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, 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;
- 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, 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 or we may be required to find alternative markets and arrangements for our natural gas and NGLs;
- 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 $1.4 billion unsecured revolving credit facility or other credit facilities, 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, infrastructure constraints 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, regulatory and protection of the environment, including, but not limited to, pending Colorado ballot initiatives, 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 attacks and breaches, against, or otherwise impacting, our facilities and systems; and
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses.

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.

PART I

Item 1. ***Financial Statements (Unaudited)***

DCP MIDSTREAM, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2018	December 31, 2017
ASSETS	(millions)	
Current assets:		
Cash and cash equivalents	$ 1	$ 156
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $6 and $8 million, respectively	989	773
Affiliates	227	191
Other	18	17
Inventories	77	68
Unrealized gains on derivative instruments	57	30
Collateral cash deposits	140	75
Other	17	12
Total current assets	1,526	1,322
Property, plant and equipment, net	9,163	8,983
Goodwill	231	231
Intangible assets, net	99	106
Investments in unconsolidated affiliates	3,277	3,050
Unrealized gains on derivative instruments	19	3
Other long-term assets	170	183
Total assets	$ 14,485	$ 13,878
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 1,176	$ 989
Affiliates	106	68
Other	40	19
Current debt	525	—
Unrealized losses on derivative instruments	157	76
Accrued interest	68	71
Accrued taxes	81	58
Accrued wages and benefits	52	65
Capital spending accrual	49	39
Other	79	103
Total current liabilities	2,333	1,488
Long-term debt	4,575	4,707
Unrealized losses on derivative instruments	37	15
Deferred income taxes	29	29
Other long-term liabilities	235	201
Total liabilities	7,209	6,440
Commitments and contingent liabilities (see note 14)		
Equity:		
Series A preferred limited partners (500,000 preferred units authorized, issued and outstanding, respectively)	498	491
Series B preferred limited partners (6,450,000 preferred units authorized, issued and outstanding, respectively)	156	—
General partner	109	154
Limited partners (143,317,328 and 143,309,828 common units authorized, issued and outstanding, respectively)	6,491	6,772
Accumulated other comprehensive loss	(8)	(9)
Total partners' equity	7,246	7,408
Noncontrolling interests	30	30
Total equity	7,276	7,438
Total liabilities and equity	$ 14,485	$ 13,878

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,	
	2018	2017	2018	2017
	(millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, NGLs and condensate	$ 2,191	$ 1,618	$ 5,784	$ 4,756
Sales of natural gas, NGLs and condensate to affiliates	491	318	1,224	885
Transportation, processing and other	133	162	371	474
Trading and marketing (losses) gains, net	(56)	(43)	(164)	10
Total operating revenues	2,759	2,055	7,215	6,125
Operating costs and expenses:				
Purchases and related costs	2,074	1,550	5,381	4,528
Purchases and related costs from affiliates	253	145	643	411
Operating and maintenance expense	196	168	543	513
Depreciation and amortization expense	98	94	289	282
General and administrative expense	70	69	199	202
Asset impairments	—	48	—	48
Other expense, net	2	—	7	15
Gain on sale of assets, net	—	—	—	(34)
Total operating costs and expenses	2,693	2,074	7,062	5,965
Operating income (loss)	66	(19)	153	160
Loss from financing activities	(19)	—	(19)	—
Earnings from unconsolidated affiliates	104	74	278	234
Interest expense, net	(69)	(73)	(203)	(219)
Income (loss) before income taxes	82	(18)	209	175
Income tax expense	—	(2)	(2)	(5)
Net income (loss)	82	(20)	207	170
Net income attributable to noncontrolling interests	(1)	—	(3)	(1)
Net income (loss) attributable to partners	81	(20)	204	169
Series A preferred limited partners' interest in net income	(10)	—	(28)	—
Series B preferred limited partners' interest in net income	(3)	—	(5)	—
General partner’s interest in net income	(42)	(39)	(123)	(122)
Net income (loss) allocable to limited partners	$ 26	$ (59)	$ 48	$ 47
Net income (loss) per limited partner unit — basic and diluted	0.18	(0.41)	0.33	0.33
Weighted-average limited partner units outstanding — basic and diluted	143.3	143.3	143.3	143.3

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(millions)			
Net income (loss)	$ 82	$ (20)	$ 207	$ 170
Other comprehensive income:				
Reclassification of cash flow hedge losses into earnings	—	—	1	1
Total other comprehensive income	—	—	1	1
Total comprehensive income (loss)	82	(20)	208	171
Total comprehensive income attributable to noncontrolling interests	(1)	—	(3)	(1)
Total comprehensive income (loss) attributable to partners	$ 81	$ (20)	$ 205	$ 170

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30,	
	2018	2017
	(millions)	
OPERATING ACTIVITIES:		
Net income	$ 207	$ 170
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	289	282
Earnings from unconsolidated affiliates	(278)	(234)
Distributions from unconsolidated affiliates	325	270
Net unrealized losses (gains) on derivative instruments	79	(1)
Gain on sale of assets, net	—	(34)
Asset impairments	—	48
Loss from financing activities	19	—
Other, net	13	29
Change in operating assets and liabilities, which provided (used) cash, net of effects of acquisitions:		
Accounts receivable	(256)	(59)
Inventories	(9)	10
Accounts payable	255	179
Other assets and liabilities	(103)	24
Net cash provided by operating activities	541	684
INVESTING ACTIVITIES:		
Capital expenditures	(428)	(258)
Investments in unconsolidated affiliates, net	(265)	(70)
Proceeds from sale of assets	3	130
Net cash used in investing activities	(690)	(198)
FINANCING ACTIVITIES:		
Proceeds from debt	3,620	—
Payments of debt	(3,225)	(195)
Costs incurred to redeem senior notes	(18)	—
Proceeds from issuance of preferred limited partner units, net of offering costs	155	—
Distributions to preferred limited partners	(25)	—
Net change in advances to predecessor from DCP Midstream, LLC	—	418
Distributions to limited partners and general partner	(503)	(390)
Distributions to noncontrolling interests	(3)	(6)
Other	(7)	(2)
Net cash used in financing activities	(6)	(175)
Net change in cash and cash equivalents	(155)	311
Cash and cash equivalents, beginning of period	156	1
Cash and cash equivalents, end of period	$ 1	$ 312

See accompanying notes to condensed consolidated financial statements.

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

	Partners' Equity						
	Series A Preferred Limited Partners	Series B Preferred Limited Partners	Limited Partners	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
	(millions)						
Balance, January 1, 2018	$ 491	$ —	$ 6,772	$ 154	$ (9)	$ 30	$ 7,438
Cumulative-effect adjustment (see Note 2)	—	—	6	—	—	—	6
Net income	28	5	48	123	—	3	207
Other comprehensive income	—	—	—	—	1	—	1
Issuance of 6,450,000 Series B Preferred Units	—	155	—	—	—	—	155
Distributions to unitholders	(21)	(4)	(335)	(168)	—	—	(528)
Distributions to noncontrolling interests	—	—	—	—	—	(3)	(3)
Balance, September 30, 2018	$ 498	$ 156	$ 6,491	$ 109	$ (8)	$ 30	$ 7,276

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, 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	—	3,094	—	(2)	—	3,092
Issuance of 28,552,480 common units and 2,550,644 general partner units to DCP Midstream, LLC and affiliate	—	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.

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 which 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. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. As of September 30, 2018, DCP Midstream, LLC owned approximately 38.1% of us, including limited partner and general partner interests.

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

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 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 U.S. Securities and Exchange Commission ("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, 2018 are not necessarily indicative of the results that may be expected for the year ending December 31, 2018. 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 2017 audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2017.

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 adopted the ASU on January 1, 2018 and it has not had any impact on our condensed consolidated results of operations, cash flows and financial position.

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 will adopt Topic 842 on January 1, 2019, and intend to elect the land easement practical expedient. In addition, we intend to elect the package of practical expedients permitted under the transition guidance within the new standard. We are currently in the process of gathering a complete population of our lease arrangements, implementing a software solution, and evaluating the impact of the new standard on our consolidated financial statements. Based on our evaluation to-date and from the perspective as the lessee, our leasing activity primarily consists of transportation agreements, office space, vehicles and equipment. Though the evaluation process is still in progress, we currently anticipate that this new lease guidance will result in changes to the way we recognize, present and disclose our operating leases in our consolidated financial statements, including the recognition of a lease liability and an offsetting right-of-use asset in our consolidated balance sheets for our operating leases (with the exception of short-term leases excluded by practical expedient).

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." We adopted this ASU on January 1, 2018 using the modified retrospective method for contracts that were not completed as of the date of adoption. Under this method, the comparative information has not been restated and continues to be reported under the accounting standards in effect for those prior periods. Under the new standard, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. We recognized the initial cumulative effect of applying this ASU as an adjustment to the opening balance of total partners' equity.

In accordance with the new revenue standard requirements, the impact of adoption on our consolidated statement of operations was as follows:

	Three Months Ended September 30, 2018			Nine Months Ended September 30, 2018		
	As Reported	Effect of Change	Presentation Without Adoption of ASC 606	As Reported	Effect of Change	Presentation Without Adoption of ASC 606
	(millions)					
Statement of Operations						
Operating revenues						
Sales of natural gas, NGLs and condensate	$ 2,191	$ 41	$ 2,232	$ 5,784	$ 116	$ 5,900
Transportation, processing and other	$ 133	$ 43	$ 176	$ 371	$ 122	$ 493
Costs and expenses						
Purchases and related costs	$ 2,074	$ 84	$ 2,158	$ 5,381	$ 238	$ 5,619
Net income	$ 82	$ —	$ 82	$ 207	$ —	$ 207

3. Revenue Recognition

Our operating revenues are primarily derived from the following activities:

- sales of natural gas, NGLs, and condensate;
- services related to gathering, compressing, treating and processing NGLs and natural gas; and
- services related to transportation and storage of natural gas and NGLs.

Sales of natural gas, NGLs and condensate - We sell our commodities to a variety of customers ranging from large, multi-national petrochemical and refining companies to regional retail propane distributors. We recognize revenue from commodity sales at the point in time when the product is delivered to the customer. Generally, the transaction price is determined at the time of each delivery as the uncertainty of commodity pricing is resolved. Customers usually pay monthly based on the products purchased that month.

Sales of natural gas, NGLs and condensate include physical sales contracts which qualify as financial derivative instruments, and buy-sell and exchange transactions which involve purchases and sales of inventory with the same counterparty that are legally contingent or in contemplation of one another as a single transaction on a combined net basis. Neither of these types of arrangements are contracts with customers within the scope of Topic 606.

Gathering, compressing, treating and processing natural gas - For natural gas gathering and processing activities, we receive either fees and/or a percentage of proceeds from commodity sales as payment for these services, depending on the type of contract. For gathering and processing agreements within the scope of Topic 606, we recognize the revenue associated with our services when the gas is gathered, treated or processed at our facilities. Under fee-based contracts, we receive a fee for our services based on throughput volumes. Under percent-of-proceeds contracts, we receive either an agreed upon percentage of the actual proceeds received from our sale of the residue natural gas and NGLs or an agreed upon percentage based on index related prices for the natural gas and NGLs. Our percent-of-proceeds contracts may also include a fee-based component.

Transportation and storage - Revenue from transportation and storage agreements is recognized based on contracted volumes transported and stored in the period the services are provided.

Our service contracts generally have terms that extend beyond one year, and are recognized over time. The performance obligation for most of our service contracts encompasses a series of distinct services performed on discrete daily quantities of natural gas or NGLs for purposes of allocating variable consideration and recognizing revenue while the customer simultaneously receives and consumes the benefits of the services provided. Revenue is recognized over time consistent with the transfer of good or service over time to the customer based on daily volumes delivered. Consideration is generally variable, and the transaction price cannot be determined at the inception of the contract, because the volume of natural gas or NGLs for which the service is provided is only specified on a daily or monthly basis. The transaction price is determined at the time the service is provided and the uncertainty is resolved. Customers usually pay monthly based on the services performed that month.

Purchase arrangements - Under purchase arrangements, we purchase natural gas at either the wellhead or the tailgate of a plant. These purchase arrangements represent an arrangement with a supplier and are recorded in “Purchases and related costs”. Often, we earn fees for services performed prior to taking control of the product in these arrangements and service revenue is recorded for these fees. Revenue generated from the sale of product obtained in these purchase arrangements are reported as “Sales of natural gas, NGLs and condensate” on the consolidated statements of operations and are recognized on a gross basis as we purchase and take control of the product prior to sale and are the principal in the transaction.

Practical expedients - We apply the practical expedients in Topic 606 and do not disclose information about transaction prices allocated to remaining performance obligations that have original expected durations of one year or less, nor do we disclose information about transaction prices allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation.

We disaggregate our revenue from contracts with customers by type for each of our reportable segments, as we believe it best depicts the nature, timing and uncertainty of our revenue and cash flows. The following tables set forth our revenue by those categories:

Revenue by type was as follows:

	Three Months Ended September 30, 2018			
	Gathering and Processing	Logistics and Marketing	Eliminations	Total
	(millions)			
Sales of natural gas	$ 469	$ 530	$ (410)	$ 589
Sales of NGLs and condensate (a)	1,053	2,040	(1,000)	2,093
Transportation, processing and other	118	15	—	133
Trading and marketing losses, net (c)	(61)	5	—	(56)
Total operating revenues	$ 1,579	$ 2,590	$ (1,410)	$ 2,759

	Nine Months Ended September 30, 2018			
	Gathering and Processing	Logistics and Marketing	Eliminations	Total
	(millions)			
Sales of natural gas	$ 1,313	$ 1,546	$ (1,182)	$ 1,677
Sales of NGLs and condensate (b)	2,663	5,210	(2,542)	5,331
Transportation, processing and other	327	45	(1)	371
Trading and marketing losses, net (c)	(124)	(40)	—	(164)
Total operating revenues	$ 4,179	$ 6,761	$ (3,725)	$ 7,215

(a) Includes $1,379 million of revenues from physical sales contracts and buy-sell exchange transactions in our logistics and marketing segment, which are not within the scope of Topic 606.
(b) Includes $3,280 million of revenues from physical sales contracts and buy-sell exchange transactions in our logistics and marketing segment, which are not within the scope of Topic 606.
(c) Not within the scope of Topic 606.

4. Contract Liabilities

We have contracts with customers whereby the customer reimburses us for costs to construct certain connections to our operating assets. These agreements are typically entered into in contemplation with gathering and processing agreements and transportation agreements with customers, and are part of the consideration of the contract. Prior to the adoption of Topic 606, we accounted for these arrangements as a reduction to the cost basis of our long-lived assets which were amortized as a reduction to depreciation expense over the estimated useful life of the related assets. Under Topic 606, we record these payments as deferred revenue which will be amortized into revenue over the expected contract term. The noncurrent portion of deferred revenue is included in other long-term liabilities on our condensed consolidated balance sheet.

The following table summarizes changes in contract liabilities included in our condensed consolidated balance sheet:

	September 30, 2018
	(millions)
Balance, beginning of period	$ —
Cumulative effect of implementation of Topic 606	36
Revenue recognized (a)	(2)
Balance, end of period	$ 34
Current contract liabilities	—
Long-term contract liabilities	$ 34

(a) Deferred revenue recognized is included in transportation, processing and other on the condensed consolidated statement of operations.

The contract liabilities disclosed in the table above will be recognized as revenue as the obligations are satisfied over the next 35 years as of September 30, 2018.

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Services Agreement and Other General and Administrative Charges

Under the Services and Employee Secondment Agreement (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,	
	2018	2017	2018	2017
	(millions)			
Employee related costs charged by DCP Midstream, LLC				
Operating and maintenance expense	$ 54	$ 50	$ 156	$ 149
General and administrative expense	$ 51	$ 46	$ 136	$ 116

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. CPChem is owned 50% by Phillips 66, and is considered a related party. Approximately 18% of our NGL production was committed to Phillips 66 and CPChem as of September 30, 2018. The primary production commitment on certain contracts began a ratable wind down period in December 2014 which 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 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.

Summary of Transactions with Affiliates

The following table summarizes our transactions with affiliates:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(millions)			
Phillips 66 (including its affiliates):				
Sales of natural gas, NGLs and condensate to affiliates	$ 483	$ 289	$ 1,166	$ 814
Purchases and related costs from affiliates	$ 57	$ 7	$ 95	$ 22
Operating and maintenance and general administrative expenses	$ 4	$ —	$ 10	$ 1
Enbridge (including its affiliates):				
Sales of natural gas, NGLs and condensate to affiliates	$ (13)	$ 14	$ 12	$ 34
Purchases and related costs from affiliates	$ (2)	$ 12	$ 26	$ 31
Operating and maintenance and general administrative expenses	$ —	$ 1	$ —	$ 2
Unconsolidated affiliates:				
Sales of natural gas, NGLs and condensate to affiliates	$ 21	$ 15	$ 46	$ 37
Transportation, processing, and other to affiliates	$ 2	$ 1	$ 5	$ 4
Purchases and related costs from affiliates	$ 198	$ 126	$ 522	$ 358

We had balances with affiliates as follows:

	September 30, 2018	December 31, 2017
	(millions)	
Phillips 66 (including its affiliates):		
Accounts receivable	$ 198	$ 156
Accounts payable	$ 25	$ 6
Other assets	$ 1	$ —
Enbridge (including its affiliates):		
Accounts receivable	$ 1	$ 11
Accounts payable	$ 5	$ 9
Unconsolidated affiliates:		
Accounts receivable	$ 28	$ 24
Accounts payable	$ 76	$ 53
Other assets	$ 1	$ 4

6. Inventories

Inventories were as follows:

	September 30, 2018	December 31, 2017
	(millions)	
Natural gas	$ 16	$ 30
NGLs	61	38
Total inventories	$ 77	$ 68

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 and related costs in the condensed consolidated statements of operations. We recognized no lower of cost or net realizable value adjustments during the three and nine months ended September 30, 2018 and September 30, 2017, respectively.

7. Property, Plant and Equipment

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

	Depreciable Life	September 30, 2018	December 31, 2017
		(millions)	
Gathering and transmission systems	20 — 50 Years	$ 8,737	$ 8,473
Processing, storage and terminal facilities	35 — 60 Years	5,317	5,128
Other	3 — 30 Years	564	557
Construction work in progress		382	374
Property, plant and equipment		15,000	14,532
Accumulated depreciation		(5,837)	(5,549)
Property, plant and equipment, net		$ 9,163	$ 8,983

Interest capitalized on construction projects was $4 million and $2 million for the three months ended September 30, 2018 and 2017, respectively, and $15 million and $4 million for the nine months ended September 30, 2018 and 2017, respectively.

Depreciation expense was $95 million and $90 million for the three months ended September 30, 2018 and 2017, respectively, and $281 million and $272 million for the nine months ended September 30, 2018 and 2017, respectively.

8. Goodwill

We performed our annual goodwill assessment during the third quarter of 2018 at the reporting unit level, which is conducted by assessing whether (i) the components of our operating segments constitute businesses for which discrete financial information is available, (ii) segment management regularly reviews the operating results of those components and (iii) 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 approximately 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 our goodwill 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 its 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.

During the three and nine months ended September 30, 2018, we had no additions to or dispositions from the carrying amount of goodwill in each of our reportable segments. The carrying amount of goodwill in each of our reportable segments was as follows:

	September 30, 2018 (millions)		
	Gathering and Processing	Logistics and Marketing	Total
Balance, end of period	$ 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, 2018	Carrying Value as of December 31, 2017
		(millions)	
DCP Sand Hills Pipeline, LLC	66.67%	$ 1,774	$ 1,633
DCP Southern Hills Pipeline, LLC	66.67%	733	739
Discovery Producer Services LLC	40.00%	350	362
Front Range Pipeline LLC	33.33%	175	165
Texas Express Pipeline LLC	10.00%	92	90
Gulf Coast Express Pipeline LLC	25.00%	89	—
Mont Belvieu Enterprise Fractionator	12.50%	27	23
Panola Pipeline Company, LLC	15.00%	23	24
Mont Belvieu 1 Fractionator	20.00%	10	10
Other	Various	4	4
Total investments in unconsolidated affiliates		$ 3,277	$ 3,050

Earnings from investments in unconsolidated affiliates were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(millions)			
DCP Sand Hills Pipeline, LLC	$ 64	$ 37	$ 170	$ 105
DCP Southern Hills Pipeline, LLC	21	10	50	34
Discovery Producer Services LLC	1	14	4	59
Front Range Pipeline LLC	6	5	16	12
Texas Express Pipeline LLC	4	4	14	7
Mont Belvieu Enterprise Fractionator	3	3	10	10
Mont Belvieu 1 Fractionator	4	2	12	6
Other	1	(1)	2	1
Total earnings from unconsolidated affiliates	$ 104	$ 74	$ 278	$ 234

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(millions)			
Statements of operations:				
Operating revenue	$ 407	$ 358	$ 1,149	$ 1,063
Operating expenses	$ 157	$ 164	$ 443	$ 464
Net income	$ 250	$ 194	$ 704	$ 598

	September 30, 2018	December 31, 2017
	(millions)	
Balance sheets:		
Current assets	$ 557	$ 244
Long-term assets	5,937	5,319
Current liabilities	(412)	(196)
Long-term liabilities	(237)	(200)
Net assets	$ 5,845	$ 5,167

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 with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, data obtained from third-party pricing services, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming online, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

Nonfinancial Assets and Liabilities

We utilize fair value to perform impairment tests as required on our property, plant and equipment, goodwill, equity investments, 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, 2018, we recognized no impairments of property, plant and equipment, intangible assets and investment in unconsolidated affiliates. 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 condensed consolidated balance sheet caption and by valuation hierarchy, as of and for the nine months ended September 30, 2017:

	Net Carrying Value	Fair Value Measurements Using			Asset Impairments
		Level 1	Level 2	Level 3	
	(millions)				
Property, plant and equipment	$ 14	$ —	$ —	$ 14	$ 26
Intangible assets	11	—	—	11	21
Investment in unconsolidated affiliates	1	—	—	1	1
Total impairments	$ 26	$ —	$ —	$ 26	$ 48

The following table presents the financial instruments carried at fair value as of September 30, 2018 and December 31, 2017, by condensed consolidated balance sheet caption and by valuation hierarchy, as described above:

	September 30, 2018				December 31, 2017			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(millions)							
Current assets:								
Commodity derivatives (a)	$ 44	$ 9	$ 4	$ 57	$ 10	$ 17	$ 3	$ 30
Short-term investments (b)	$ —	$ —	$ —	$ —	$ 156	$ —	$ —	$ 156
Long-term assets:								
Commodity derivatives (c)	$ 15	$ 2	$ 2	$ 19	$ 1	$ 1	$ 1	$ 3
Current liabilities:								
Commodity derivatives (d)	$ (82)	$ (57)	$ (18)	$ (157)	$ (29)	$ (34)	$ (13)	$ (76)
Long-term liabilities:								
Commodity derivatives (e)	$ (25)	$ (7)	$ (5)	$ (37)	$ (3)	$ (11)	$ (1)	$ (15)

(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 nine months ended September 30, 2018 and 2017, 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, 2018 (a):				
Beginning balance	$ 1	$ 1	$ (10)	$ (7)
Net unrealized gains (losses) included in earnings (b)	4	1	(20)	2
Transfers out of Level 3 (c)	(1)	—	5	—
Settlements	—	—	7	—
Ending balance	$ 4	$ 2	$ (18)	$ (5)
Net unrealized gains (losses) on derivatives still held included in earnings (b)	$ 3	$ 1	$ (15)	$ 2
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 on derivatives still held included in earnings (b)	$ 3	$ 2	$ (22)	$ —

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(millions)			
Nine months ended September 30, 2018 (a):				
Beginning balance	$ 3	$ 1	$ (13)	$ (1)
Net unrealized gains (losses) included in earnings (b)	2	1	(28)	(4)
Transfers out of Level 3 (c)	(1)	—	10	—
Settlements	—	—	13	—
Ending balance	$ 4	$ 2	$ (18)	$ (5)
Net unrealized gains (losses) on derivatives still held included in earnings (b)	$ 4	$ 1	$ (17)	$ (4)
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)

(a) There were no purchases, issuances or sales of derivatives or transfers into Level 3 for the three and nine months ended September 30, 2018 and 2017.
(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, 2018			
Product Group	**Fair Value**		**Forward Curve Range**	
	(millions)			
Assets				
NGLs	$	4	$0.38-$1.29	Per gallon
Natural gas	$	2	$1.87-$2.43	Per MMBtu
Liabilities				
NGLs	$	(22)	$0.15-$1.29	Per gallon
Natural gas	$	(1)	$2.37-$2.80	Per MMBtu

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 relationships 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 and accounts payable 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. The fair value of borrowings under the Credit Agreement and our Accounts Receivable Securitization Facility (the "Securitization Facility") are based on carrying value, which approximates fair value as their interest rates are based on prevailing market interest rates. We classify the fair values of our outstanding debt balances within Level 2 of the valuation hierarchy. As of September 30, 2018 and December 31, 2017, the carrying value and fair value of our total debt, including current maturities, were as follows:

	September 30, 2018		December 31, 2017	
	Carrying Value (a)	Fair Value	Carrying Value (a)	Fair Value
	(millions)			
Total debt	$ 5,131	$ 5,199	$ 4,736	$ 4,885

(a) Excludes unamortized issuance costs.

11. Debt

	September 30, 2018	December 31, 2017
	(millions)	
Senior notes:		
Issued February 2009, interest at 9.750% payable semiannually, due March 2019	$ —	$ 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 July 2018, interest at 5.375% payable semi-annually, due July 2025	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 agreement:		
Revolving credit facility, weighted-average variable interest rate of 3.650%, as of September 30, 2018, due December 2022	145	—
Accounts Receivable Securitization Facility:		
Accounts receivable securitization facility, weighted-average variable interest rate of 3.061% as of September 30, 2018, due August 2019	200	—
Fair value adjustments related to interest rate swap fair value hedges (a)	21	23
Unamortized issuance costs	(31)	(29)
Unamortized discount	(10)	(12)
Total debt	5,100	4,707
Current debt	525	—
Total long-term debt	$ 4,575	$ 4,707

(a) The swaps associated with this debt were previously terminated. The remaining long-term fair value of approximately $21 million related to the swaps is being amortized as a reduction to interest expense through 2020 and 2030, the original maturity dates of the debt.

Accounts Receivable Securitization Facility

In August 2018, we entered into our Securitization Facility that provides up to $200 million of borrowing capacity through August 2019 at LIBOR market index rates plus a margin. Under this Securitization Facility, certain of the Partnership's wholly owned subsidiaries sell or contribute receivables to another of the Partnership's consolidated subsidiaries, DCP Receivables LLC ("DCP Receivables"), a bankruptcy-remote special purpose entity created for the sole purpose of this Securitization Facility.

DCP Receivables' sole activity consists of purchasing receivables from the Partnership's wholly owned subsidiaries that participate in the Securitization Facility and providing these receivables as collateral for DCP Receivables' borrowings under the Securitization Facility. DCP Receivables is a separate legal entity and the accounts receivable of DCP Receivables, up to the amount of the outstanding debt under the Securitization Facility, are not available to satisfy the claims of creditors of the Partnership, its subsidiaries selling receivables under the Securitization Facility, or their affiliates. Any excess receivables are eligible to satisfy the claims of creditors of the Partnership, its subsidiaries selling receivables under the Securitization Facility, or their affiliates. The amount available for borrowing is based on the availability of eligible receivables and other customary factors and conditions. As of September 30, 2018, DCP Receivables had $838 million of our accounts receivable under its

Securitization Facility. Borrowings under the Securitization Facility are included in “Current debt” on the condensed consolidated balance sheet.

Senior Notes Redemption

In August 2018, we redeemed our outstanding $450 million 9.750% Senior Notes due March 2019, totaling $468 million in aggregate principal and make-whole payments, at a price of 104.008% plus accrued interest through the redemption date. The redemption resulted in a $19 million loss, which is reflected as loss from financing activities on the condensed consolidated statements of operations.

Senior Notes Issuance

On July 17, 2018, we issued $500 million of 5.375% Senior Notes due July 2025, unless redeemed prior to maturity. We received proceeds of $495 million, net of underwriters’ fees, related expenses and unamortized discounts which we used to redeem our $450 million 9.750% Senior Notes due March 2019. Interest on the notes will be paid semi-annually in arrears on January 15 and July 15 of each year, commencing January 15, 2019.

Credit Agreement

We are a party to a $1.4 billion unsecured revolving Credit Agreement (the "Credit Agreement") which matures on December 6, 2022. The Credit Agreement also grants us the option to increase the revolving loan commitment by an aggregate principal amount of up to $500 million, subject to requisite lender approval. The Credit Agreement may be extended for up to two additional one-year periods subject to requisite lender approval. Loans under the Credit Agreement may be used for working capital 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 Consolidated Leverage Ratio of the Partnership as of the end of any fiscal quarter shall not exceed 5.00 to 1.0 for each fiscal quarter ending after September 30, 2018; provided that, if there is a Qualified Acquisition (as defined in the Credit Agreement) during any fiscal quarter ending September 30, 2018 or thereafter, the maximum Consolidated Leverage Ratio shall not exceed 5.50 to 1.0 at the end of the three consecutive fiscal quarters, including the fiscal quarter in which the Qualified Acquisition occurs.

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 0.30% based on our current credit rating. This fee is paid on drawn and undrawn portions of the $1.4 billion revolving credit facility.

As of September 30, 2018, we had unused borrowing capacity of $1,242 million, net of $13 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 the unused borrowing capacity of $1,242 million as of September 30, 2018. Except in the case of a default, amounts borrowed under our Credit Agreement will not become due prior to the December 6, 2022 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 debt as of September 30, 2018 are as follows:

	Debt Maturities
	(millions)
2018	$ —
2019	525
2020	600
2021	500
2022	495
Thereafter	3,000
Total debt	$ 5,120

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, 2018.

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. As of September 30, 2018 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 2020. The commodity derivative instruments used for our hedging programs are a combination of direct NGL product, crude oil and natural gas hedges. 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.

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 18% of our NGL production was committed to Phillips 66 and CPChem as of September 30, 2018. 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 acceptable security for payment.

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, 2018, 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, 2018, 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, 2018, we have not been required to post additional collateral.

Collateral

As of September 30, 2018, we had cash deposits of $140 million, included in collateral cash deposits in our condensed consolidated balance sheets. Additionally, as of September 30, 2018, we held cash of $3 million, included in other current liabilities in our condensed consolidated balance sheet, related to cash postings by third parties and letters of credit of $73 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, 2018			December 31, 2017		
	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	$ 76	$ —	$ 76	$ 33	$ —	$ 33
Liabilities:						
Commodity derivatives	$ (194)	$ —	$ (194)	$ (91)	$ —	$ (91)

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, 2018 and December 31, 2017.

Balance Sheet Line Item	September 30, 2018	December 31, 2017	Balance Sheet Line Item	September 30, 2018	December 31, 2017
	(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	$ 57	$ 30	Unrealized losses on derivative instruments — current	$ (157)	$ (76)
Unrealized gains on derivative instruments — long-term	19	3	Unrealized losses on derivative instruments — long-term	(37)	(15)
Total	$ 76	$ 33	Total	$ (194)	$ (91)

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, 2018:

	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	—	—	—	—
Net deferred (losses) gains in AOCI (ending balance)	$ (3)	$ (6)	$ 1	$ (8)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$ —	$ —	$ —	$ —

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, 2018:

	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)
Losses reclassified from AOCI to earnings — effective portion	1	—	—	1
Net deferred (losses) gains in AOCI (ending balance)	$ (3)	$ (6)	$ 1	$ (8)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$ (1)	$ —	$ —	$ (1)

(a) Relates to Discovery Producer Services LLC ("Discovery"), an unconsolidated affiliate.

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)

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	(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, 2018 and 2017, 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, 2018 and 2017, 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,	
	2018	2017	2018	2017
		(millions)		
Realized (losses) gains	$ (43)	$ 16	$ (85)	$ 9
Unrealized (losses) gains	(13)	(59)	(79)	1
Trading and marketing (losses) gains, net	$ (56)	$ (43)	$ (164)	$ 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, 2018			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net Short Position (Bbls)	Net Short Position (MMBtu)	Net Short Position (Bbls)	Net (Short) Long Position (MMBtu)
2018	(721,000)	(9,938,000)	(13,436,719)	(1,652,500)
2019	(1,994,000)	(16,508,750)	(21,595,027)	(4,532,500)
2020	(189,000)	—	(13,601,378)	3,660,000
2021	—	—	(5,754,322)	—

	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

13. Partnership Equity and Distributions

Common Units — During the nine months ended September 30, 2018 and 2017, we issued no common units pursuant to our at-the-market program. As of September 30, 2018, $750 million of common units remained available for sale pursuant to our at-the-market program.

Distributions — The following table presents our cash distributions paid in 2018 and 2017:

Payment Date	Per Unit Distribution	Total Cash Distribution
		(millions)
Distributions to common unitholders		
August 14, 2018	$ 0.7800	$ 154
May 15, 2018	$ 0.7800	$ 155
February 14, 2018	$ 0.7800	$ 194
November 14, 2017	$ 0.7800	$ 155
August 14, 2017	$ 0.7800	$ 134
May 15, 2017	$ 0.7800	$ 135
February 14, 2017	$ 0.7800	$ 121
Distributions to Series A Preferred unitholders		
June 15, 2018	$ 41.9965	$ 21
Distributions to Series B Preferred unitholders		
September 17, 2018	$ 0.6781	$ 4

14. Net Income or Loss per Limited Partner Unit

Basic and diluted net income or loss per Limited Partner Unit ("LPU") is calculated by dividing net income or loss allocable to limited partners, by the weighted-average number of LPUs outstanding during the period. Diluted net income or loss per LPU is computed based on the weighted average number of units plus the effect of potential dilutive 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: (i) general liability insurance covering third-party exposures; (ii) statutory workers' compensation insurance; (iii) automobile liability insurance for all owned, non-owned and hired vehicles; (iv) excess liability insurance above the established primary limits for general liability and automobile liability insurance; (v) property insurance, which covers the replacement value of real and personal property and includes business interruption; and (vi) 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 from (i) 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) federal regulatory agencies regarding pipeline system safety which could impose additional regulatory burdens and increase the cost of our operations, (iii) state and federal regulatory officials regarding the emission of greenhouse gases, which could impose regulatory burdens and increase the cost of our operations, and (iv) regulatory bodies and communities that could prevent or delay the development of fossil fuel energy infrastructure such as pipelines, plants, and other facilities used in our business. 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.

In June 2017, we were issued a Compliance Advisory by the Colorado Department of Public Health and Environment (CDPHE) regarding alleged noncompliance with various terms and requirements of the air permit for our Lucerne 2 natural gas processing plant. Following information exchanges and discussions with CDPHE, on November 1, 2018, we entered into a Compliance Order on Consent to resolve the alleged noncompliance. The Compliance Order provides for our payment of a $46,200 administrative penalty and to fund Supplemental Environmental Projects in the amount of $184,800 to offset administrative penalties.

16. Business Segments

Our operations are organized into two reportable segments: (i) Gathering and Processing and (ii) Logistics and Marketing. 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 in Note 2 of the Notes to Consolidated Financial Statements in “Financial Statements and Supplementary Data” included as Item 8 in our Annual Report on Form 10-K for the year ended December 31, 2017.

Our Gathering and Processing segment consists of gathering, compressing, treating, processing natural gas, producing and fractionating NGLs, and recovering 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, 2018

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
			(millions)		
Total operating revenue	$ 1,579	$ 2,590	$ —	$ (1,410)	$ 2,759
Gross margin (a)	$ 364	$ 68	$ —	$ —	$ 432
Operating and maintenance expense	(175)	(14)	(7)	—	(196)
Depreciation and amortization expense	(87)	(5)	(6)	—	(98)
General and administrative expense	(6)	(3)	(61)	—	(70)
Other expense	(1)	—	(1)	—	(2)
Loss from financing activities	—	—	(19)	—	(19)
Earnings from unconsolidated affiliates	2	102	—	—	104
Interest expense	—	—	(69)	—	(69)
Net income (loss)	$ 97	$ 148	$ (163)	$ —	$ 82
Net income attributable to noncontrolling interests	(1)	—	—	—	(1)
Net income (loss) attributable to partners	$ 96	$ 148	$ (163)	$ —	$ 81
Non-cash derivative mark-to-market (b)	$ (21)	$ 8	$ —	$ —	$ (13)
Capital expenditures	$ 152	$ 3	$ 5	$ —	$ 160
Investments in unconsolidated affiliates, net	$ 3	$ 136	$ —	$ —	$ 139

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 impairment	(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

Nine Months Ended September 30, 2018:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
			(millions)		
Total operating revenue	$ 4,179	$ 6,761	$ —	$ (3,725)	$ 7,215
Gross margin (a)	$ 1,049	$ 142	$ —	$ —	$ 1,191
Operating and maintenance expense	(492)	(36)	(15)	—	(543)
Depreciation and amortization expense	(258)	(11)	(20)	—	(289)
General and administrative expense	(12)	(9)	(178)	—	(199)
Other expense, net	(4)	(2)	(1)	—	(7)
Loss from financing activities	—	—	(19)	—	(19)
Earnings from unconsolidated affiliates	5	273	—	—	278
Interest expense	—	—	(203)	—	(203)
Income tax expense	—	—	(2)	—	(2)
Net income (loss)	$ 288	$ 357	$ (438)	$ —	$ 207
Net income attributable to noncontrolling interests	(3)	—	—	—	(3)
Net income (loss) attributable to partners	$ 285	$ 357	$ (438)	$ —	$ 204
Non-cash derivative mark-to-market (b)	$ (49)	$ (30)	$ —	$ —	$ (79)
Capital expenditures	$ 412	$ 4	$ 12	$ —	$ 428
Investments in unconsolidated affiliates, net	$ 4	$ 261	$ —	$ —	$ 265

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 impairment	(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

	September 30, 2018	December 31, 2017
	(millions)	
Segment long-term assets:		
Gathering and Processing	$ 9,098	$ 8,943
Logistics and Marketing	3,584	3,348
Other (c)	277	265
Total long-term assets	12,959	12,556
Current assets	1,526	1,322
Total assets	$ 14,485	$ 13,878

(a) Gross margin consists of total operating revenues, including commodity derivative activity, less purchases and related costs. 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 net cash provided by operating activities as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

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

(c) 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,	
	2018	2017
	(millions)	
Cash paid for interest:		
Cash paid for interest, net of amounts capitalized	$ 192	$ 218
Cash paid for income taxes, net of income tax refunds	$ 3	$ 2
Non-cash investing and financing activities:		
Property, plant and equipment acquired with accounts payable and accrued liabilities	$ 58	$ 27
Other non-cash changes in property, plant and equipment	$ —	$ (1)
Issuance of common and general partner units	$ —	$ 1,125
Deficit purchase price	$ —	$ 3,094

18. Supplementary Information - Condensed Consolidating Financial Information

The following condensed consolidating financial information presents the results of operations, financial position and cash flows of DCP Midstream, 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 Sheets
September 30, 2018

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ —	$ 1	$ —	$ 1
Accounts receivable, net	—	—	1,234	—	1,234
Inventories	—	—	77	—	77
Other	—	—	214	—	214
Total current assets	—	—	1,526	—	1,526
Property, plant and equipment, net	—	—	9,163	—	9,163
Goodwill and intangible assets, net	—	—	330	—	330
Advances receivable — consolidated subsidiaries	2,522	1,739	—	(4,261)	—
Investments in consolidated subsidiaries	4,724	7,953	—	(12,677)	—
Investments in unconsolidated affiliates	—	—	3,277	—	3,277
Other long-term assets	—	—	189	—	189
Total assets	$ 7,246	$ 9,692	$ 14,485	$ (16,938)	$ 14,485
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 68	$ 1,740	$ —	$ 1,808
Current maturities of long-term debt	—	325	200	—	525
Advances payable — consolidated subsidiaries	—	—	4,261	(4,261)	—
Long-term debt	—	4,575	—	—	4,575
Other long-term liabilities	—	—	301	—	301
Total liabilities	—	4,968	6,502	(4,261)	7,209
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Net equity	7,246	4,727	7,958	(12,677)	7,254
Accumulated other comprehensive loss	—	(3)	(5)	—	(8)
Total partners' equity	7,246	4,724	7,953	(12,677)	7,246
Noncontrolling interests	—	—	30	—	30
Total equity	7,246	4,724	7,983	(12,677)	7,276
Total liabilities and equity	$ 7,246	$ 9,692	$ 14,485	$ (16,938)	$ 14,485

	Condensed Consolidating Balance Sheets December 31, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 155	$ 1	$ —	$ 156
Accounts receivable, net	—	—	981	—	981
Inventories	—	—	68	—	68
Other	—	—	117	—	117
Total current assets	—	155	1,167	—	1,322
Property, plant and equipment, net	—	—	8,983	—	8,983
Goodwill and intangible assets, net	—	—	337	—	337
Advances receivable — consolidated subsidiaries	2,895	1,614	—	(4,509)	—
Investments in consolidated subsidiaries	4,513	7,522	—	(12,035)	—
Investments in unconsolidated affiliates	—	—	3,050	—	3,050
Other long-term assets	—	—	186	—	186
Total assets	$ 7,408	$ 9,291	$ 13,723	$ (16,544)	$ 13,878
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 71	$ 1,417	$ —	$ 1,488
Advances payable — consolidated subsidiaries	—	—	4,509	(4,509)	—
Long-term debt	—	4,707	—	—	4,707
Other long-term liabilities	—	—	245	—	245
Total liabilities	—	4,778	6,171	(4,509)	6,440
Commitments and contingent liabilities					
Equity:					
Partners’ equity:					
Net equity	7,408	4,517	7,527	(12,035)	7,417
Accumulated other comprehensive loss	—	(4)	(5)	—	(9)
Total partners’ equity	7,408	4,513	7,522	(12,035)	7,408
Noncontrolling interests	—	—	30	—	30
Total equity	7,408	4,513	7,552	(12,035)	7,438
Total liabilities and equity	$ 7,408	$ 9,291	$ 13,723	$ (16,544)	$ 13,878

Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2018

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(millions)		
Operating revenues:					
Sales of natural gas, NGLs and condensate	$ —	$ —	$ 2,682	$ —	$ 2,682
Transportation, processing and other	—	—	133	—	133
Trading and marketing losses, net	—	—	(56)	—	(56)
Total operating revenues	—	—	2,759	—	2,759
Operating costs and expenses:					
Purchases and related costs	—	—	2,327	—	2,327
Operating and maintenance expense	—	—	196	—	196
Depreciation and amortization expense	—	—	98	—	98
General and administrative expense	—	—	70	—	70
Other expense, net	—	—	2	—	2
Total operating costs and expenses	—	—	2,693	—	2,693
Operating income	—	—	66	—	66
Loss from financing activities	—	(19)	—	—	(19)
Interest expense, net	—	(68)	(1)	—	(69)
Income from consolidated subsidiaries	81	168	—	(249)	—
Earnings from unconsolidated affiliates	—	—	104	—	104
Income before income taxes	81	81	169	(249)	82
Income tax expense	—	—	—	—	—
Net income	81	81	169	(249)	82
Net income attributable to noncontrolling interests	—	—	(1)	—	(1)
Net income attributable to partners	$ 81	$ 81	$ 168	$ (249)	$ 81

Condensed Consolidating Statement of Comprehensive Income
Three Months Ended September 30, 2018

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(millions)		
Net income	$ 81	$ 81	$ 169	$ (249)	$ 82
Total other comprehensive income	—	—	—	—	—
Total comprehensive income	81	81	169	(249)	82
Total comprehensive income attributable to noncontrolling interests	—	—	(1)	—	(1)
Total comprehensive income attributable to partners	$ 81	$ 81	$ 168	$ (249)	$ 81

	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 impairment	—	—	48	—	48
Total operating costs and expenses	—	—	2,074	—	2,074
Operating loss	—	—	(19)	—	(19)
Interest expense, net	—	(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 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
Nine Months Ended September 30, 2018

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(millions)		
Operating revenues:					
Sales of natural gas, NGLs and condensate	$ —	$ —	$ 7,008	$ —	$ 7,008
Transportation, processing and other	—	—	371	—	371
Trading and marketing losses, net	—	—	(164)	—	(164)
Total operating revenues	—	—	7,215	—	7,215
Operating costs and expenses:					
Purchases and related costs	—	—	6,024	—	6,024
Operating and maintenance expense	—	—	543	—	543
Depreciation and amortization expense	—	—	289	—	289
General and administrative expense	—	—	199	—	199
Other expense, net	—	—	7	—	7
Total operating costs and expenses	—	—	7,062	—	7,062
Operating income	—	—	153	—	153
Loss from financing activities	—	(19)	—	—	(19)
Interest expense, net	—	(202)	(1)	—	(203)
Income from consolidated subsidiaries	204	425	—	(629)	—
Earnings from unconsolidated affiliates	—	—	278	—	278
Income before income taxes	204	204	430	(629)	209
Income tax expense	—	—	(2)	—	(2)
Net income	204	204	428	(629)	207
Net income attributable to noncontrolling interests	—	—	(3)	—	(3)
Net income attributable to partners	$ 204	$ 204	$ 425	$ (629)	$ 204

Condensed Consolidating Statement of Comprehensive Income
Nine Months Ended September 30, 2018

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(millions)		
Net income	$ 204	$ 204	$ 428	$ (629)	$ 207
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	205	205	428	(630)	208
Total comprehensive income attributable to noncontrolling interests	—	—	(3)	—	(3)
Total comprehensive income attributable to partners	$ 205	$ 205	$ 425	$ (630)	$ 205

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 and related costs	—	—	4,939	—	4,939
Operating and maintenance expense	—	—	513	—	513
Depreciation and amortization expense	—	—	282	—	282
General and administrative expense	—	—	202	—	202
Asset impairment	—	—	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 Cash Flows Nine Months Ended September 30, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (201)	$ 742	$ —	$ 541
INVESTING ACTIVITIES:					
Intercompany transfers	373	(125)	—	(248)	—
Capital expenditures	—	—	(428)	—	(428)
Investments in unconsolidated affiliates, net	—	—	(265)	—	(265)
Proceeds from sale of assets	—	—	3	—	3
Net cash provided by (used in) investing activities	373	(125)	(690)	(248)	(690)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	(248)	248	—
Proceeds from debt	—	3,420	200	—	3,620
Payments of debt	—	(3,225)	—	—	(3,225)
Costs incurred to redeem senior notes	—	(18)	—	—	(18)
Proceeds from issuance of preferred limited partner units, net of offering costs	155	—	—	—	155
Distributions to preferred limited partners	(25)	—	—	—	(25)
Distributions to limited partners and general partner	(503)	—	—	—	(503)
Distributions to noncontrolling interests	—	—	(3)	—	(3)
Other	—	(6)	(1)	—	(7)
Net cash (used in) provided by financing activities	(373)	171	(52)	248	(6)
Net change in cash and cash equivalents	—	(155)	—	—	(155)
Cash and cash equivalents, beginning of period	—	155	1	—	156
Cash and cash equivalents, end of period	$ —	$ —	$ 1	$ —	$ 1

Condensed Consolidating Statements 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, net	—	—	(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 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 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

19. Subsequent Events

On October 4, 2018, we issued 4,000,000 of our Series C Preferred Units representing limited partnership interests at a price of $25 per unit. On October 19, 2018, we issued an additional 400,000 Series C Preferred Units which represented the partial exercise of the underwriters' option to purchase additional Series C Preferred Units. We used the net proceeds of $106 million from the issuance of the Series C Preferred Units for general partnership purposes including funding capital expenditures and the repayment of outstanding indebtedness under the Credit Agreement.

Distributions of the Series C Preferred Units are payable out of available cash, accrue and are cumulative from the date of original issuance of the Series C Preferred Units and are payable quarterly in arrears on January 15th, April 15th, July 15th and October 15th of each year to holders of record as of the close of business on the first business day of the month in which the distribution will be made. The initial distribution rate will be 7.95% per year of the $25 liquidation preference per unit (equal to $1.9875 per unit). On and after October 15, 2023, distributions will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR plus a spread of 4.882%. The Series C Preferred Units rank senior to our common units with respect to distribution rights and rights upon liquidation.

On October 23, 2018, we announced that the board of directors of the General Partner declared a quarterly distribution on our common units of $0.78 per common unit. The distribution will be paid on November 14, 2018 to unitholders of record on November 2, 2018.

On the same date, we announced that the board of directors of the General Partner declared a semi-annual and quarterly distribution on our Series A Preferred Units and B Preferred Units of $36.8750 and $0.4922 per unit, respectively. The distributions will be paid on December 17, 2018 to unitholders of record on December 3, 2018.

On the same date, we announced that the board of directors of the General Partner declared an initial quarterly distribution on our Series C Preferred Units of $0.5576 per Series C Preferred Unit, which includes the distribution attributable to the partial-period from and including the original issue date of October 4, 2018. The distribution will be paid on January 15, 2019 to unitholders of record on January 2, 2019.

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 in our Annual Report on Form 10-K for the year ended December 31, 2017.

Overview

We are a Delaware limited partnership formed by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. Our operations are organized into two reportable segments: (i) Gathering and Processing and (ii) Logistics and Marketing. Our Gathering and Processing segment consists of gathering, compressing, treating, and processing natural gas, producing and fractionating NGLs, and recovering condensate. Our Logistics and Marketing segment includes transporting, trading, marketing and storing natural gas and NGLs, fractionating NGLs and wholesale propane logistics.

General Trends and Outlook

We anticipate our business will continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Our business is impacted by commodity prices and volumes. We mitigate a significant portion of commodity price risk on an overall Partnership basis by growing our fee based assets and by executing on our hedging program. Various factors impact both commodity prices and volumes, and as indicated in Item 3. "Quantitative and Qualitative Disclosures about Market Risk", we have sensitivities to certain cash and non-cash changes in commodity prices.

In the long-term, our belief is that commodity prices will continue to be at levels which support growth in crude, condensate, natural gas, and NGL production. We expect future commodity prices will be influenced by the severity of winter and summer weather, tariffs and other global economic conditions, 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.

Our business is primarily driven by the level of production of natural gas by producers and of NGLs from processing plants connected to our pipelines and fractionators. These volumes can be affected by, among other things, reduced drilling activity, severe weather disruptions, operational outages and ethane rejection.

NGL prices are impacted by the balance of supply and demand from petrochemical and refining industries and export facilities. The petrochemical industry has been making significant investment in building, expanding and converting facilities to use lighter NGL-based feedstocks, including ethane in their chemical plants. As these facilities commence operations, ethane demand increases and could provide price support for increased recovery of ethane at gas processing plants. We believe these new facilities will cause increased demand over time, which should provide support for the increasing supply of ethane. 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.

We hedge commodity prices associated with a portion of our expected natural gas, NGL and condensate equity volumes in our Gathering and Processing segment. Drilling activity levels vary by geographic area; we will continue to target our strategy in geographic areas where we expect producer drilling activity.

Recent significant NGL supply growth has resulted in industry wide infrastructure constraints at pipeline and fractionation facilities. We believe we are well positioned to manage through these constraints as a large, integrated midstream company, but growth of our business could be dampened in the near term while more industry wide pipeline and fractionation facilities are developed. Although there may be infrastructure constraints in the near term, we believe our growth projects and other industry wide projects coming on-line over the next two years will help mitigate those constraints. We believe these projects being developed will enable us to meet the demand of our customers.

We believe our contract structure with our producers provides us with significant protection from credit risk 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, 10 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.

During 2018, our strategic objectives will continue to focus on maintaining stable Distributable Cash Flows from our existing assets and executing on opportunities to sustain and ultimately grow our long-term Distributable Cash Flows. We believe the key elements to stable Distributable Cash Flows are the diversity of our asset portfolio, our fee-based business which represents a significant portion of our estimated margins, plus our hedged commodity position, the objective of which is to protect against downside risk in our Distributable Cash Flows.

We 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 Logistics and Marketing Segment, we increased the capacity of the Sand Hills pipeline at the end of the third quarter of 2018 to 440 MBbls/d, with expansion to 485 MBbls/d expected by the end of 2018.
- We increased the capacity of the Southern Hills pipeline at the end of the third quarter of 2018 to 190+ MBbls/d.
- We are participating in the Front Range 100 MBls/d and Texas Express 90 MBls/d expansions adding NGL takeaway from the DJ Basin. Both expansions are expected to go into service in the third quarter of 2019.
- We have a 33% ownership option in the Cheyenne Connector pipeline. The Cheyenne Connector pipeline will have an initial capacity of at least 600 MMcf/day and is expected to be in service in the third quarter of 2019, subject to certain conditions, including required approvals from the Federal Energy Regulatory Commission.
- We are adding NGL takeaway to the DJ Basin with our Southern Hills pipeline extension via the White Cliffs NGL Pipeline, with capacity of 90 MBls/d, expandable to 120 MBls/d. Expected completion is in the fourth quarter of 2019.
- We are participating in the construction of the Gulf Coast Express pipeline, or "GCX". The approximately $1.75 billion GCX project is designed to transport approximately 2 Bcf/d of natural gas, and is fully subscribed. The natural gas takeaway pipeline is under construction and is anticipated to be in-service in the fourth quarter of 2019.
- We hold an option to acquire a 30% ownership interest in two 150 MBbls/d fractionators to be constructed within Phillips 66's Sweeny Hub, exercisable at the in-service date, which is expected to be in late 2020.
- Within our Gathering and Processing Segment, we placed our 200 MMcf/d Mewbourn 3 natural gas processing plant and associated gathering infrastructure in service in August 2018.

- Construction of our 300 MMcf/d O'Connor 2 facility and associated gathering infrastructure, located in the DJ Basin, is progressing and expected to be in service in the second quarter of 2019. O'Connor 2 is comprised of 200 MMcf/d of processing capacity and up to 100 MMcf/d of bypass.
- We have secured land and filed permits for Bighorn, a natural gas processing facility in the DJ Basin, with capacity of up to 1.0 Bcf/d including bypass. The Bighorn facility and associated gathering infrastructure is pending a final investment decision based on evaluation of the regulatory environment and drilling activity.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. Our 2018 plan includes maintenance capital expenditures of between $100 million and $120 million. We have updated our range of expansion capital expenditures to between $825 million and $900 million. Expansion capital expenditures include the construction of the O'Connor 2 plant and Mewbourn 3 plant in our DJ Basin system, as well as the capacity expansion of the Sand Hills pipeline and the construction of the Gulf Coast Express pipeline, which are shown as an investment in unconsolidated affiliates in our condensed consolidated statements of cash flows.

Our 2018 earnings from unconsolidated affiliates and distributions from unconsolidated affiliates from our investment in Discovery in our Gathering and Processing segment are forecasted to be lower than 2017 by approximately $60 million to $70 million. Approximately $30 million to $40 million of this decrease is associated with significant volume declines from two offshore wells and an additional $30 million is associated with a contractual dispute with certain producers regarding demand charges, which is being challenged by Discovery.

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 Item 7 in our Annual Report on Form 10-K for the year ended December 31, 2017.

Recent Events

Common and Preferred Distributions

On October 23, 2018, we announced that the board of directors of the General Partner declared a quarterly distribution on our common units of $0.78 per common unit. This distribution per common unit remains unchanged from the previous quarter and the third quarter of 2017. The distribution will be paid on November 14, 2018 to unitholders of record on November 2, 2018.

On the same date, we announced that the board of directors of the General Partner declared a semi-annual and quarterly distribution on our Series A Preferred Units and B Preferred Units of $36.8750 and $0.4922 per unit, respectively. The distributions will be paid on December 17, 2018 to unitholders of record on December 3, 2018.

On the same date, we announced that the board of directors of the General Partner declared an initial quarterly distribution on our Series C Preferred Units of $0.5576 per Series C Preferred Unit, which includes the distribution attributable to the partial-period from and including the original issue date of October 4, 2018. The distribution will be paid on January 15, 2019 to unitholders of record on January 2, 2019.

Preferred Units Issuance

On October 4, 2018, we issued 4,000,000 of our Series C Preferred Units representing limited partnership interests at a price of $25 per unit. On October 19, 2018, we issued an additional 400,000 Series C Preferred Units which represented the partial exercise of the underwriters’ option to purchase additional Series C Preferred Units. We used the net proceeds of $106 million from the issuance of the Series C Preferred Units for general partnership purposes including funding capital expenditures and the repayment of outstanding indebtedness under the Credit Agreement.

Accounts Receivable Securitization Facility

In August 2018, we entered into the Securitization Facility that provides up to $200 million of borrowing capacity through August 2019 at LIBOR market index rates plus a margin.

Senior Notes Redemption

In August 2018, we redeemed our outstanding $450 million 9.750% Senior Notes due March 2019, totaling $468 million in aggregate principal and make-whole payments, at a price of 104.008% plus accrued interest through the redemption date. The redemption resulted in a $19 million loss, which is reflected as loss from financing activities on the condensed consolidated statements of operations.

Senior Notes Issuance

On July 17, 2018, we issued $500 million of 5.375% Senior Notes due July 2025, unless redeemed prior to maturity. We received proceeds of $495 million, net of underwriters' fees, related expenses and unamortized discounts which we used to redeem our $450 million 9.750% Senior Notes due March 2019. Interest on the notes will be paid semi-annually in arrears on January 15 and July 15 of each year, commencing January 15, 2019.

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, 2018 and 2017. 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 2018 vs. 2017		Variance Nine Months 2018 vs. 2017	
	2018	2017	2018	2017	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(millions, except operating data)							
Operating revenues (a):								
Gathering and Processing	$ 1,579	$ 1,337	$ 4,179	$ 3,965	$ 242	18 %	$ 214	5 %
Logistics and Marketing	2,590	1,913	6,761	5,596	677	35 %	1,165	21 %
Inter-segment eliminations	(1,410)	(1,195)	(3,725)	(3,436)	215	18 %	289	8 %
Total operating revenues	2,759	2,055	7,215	6,125	704	34 %	1,090	18 %
Purchases and related costs								
Gathering and Processing	(1,215)	(1,034)	(3,130)	(2,944)	181	18 %	186	6 %
Logistics and Marketing	(2,522)	(1,856)	(6,619)	(5,431)	666	36 %	1,188	22 %
Inter-segment eliminations	1,410	1,195	3,725	3,436	215	18 %	289	8 %
Total purchases	(2,327)	(1,695)	(6,024)	(4,939)	632	37 %	1,085	22 %
Operating and maintenance expense	(196)	(168)	(543)	(513)	28	17 %	30	6 %
Depreciation and amortization expense	(98)	(94)	(289)	(282)	4	4 %	7	2 %
General and administrative expense	(70)	(69)	(199)	(202)	1	1 %	(3)	(1)%
Asset impairments	—	(48)	—	(48)	(48)	*	(48)	*
Other expense, net	(2)	—	(7)	(15)	2	*	(8)	(53)%
Gain on sale of assets, net	—	—	—	34	—	*	(34)	*
Loss from financing activities	(19)	—	(19)	—	19	*	19	*
Earnings from unconsolidated affiliates (b)	104	74	278	234	30	41 %	44	19 %
Interest expense	(69)	(73)	(203)	(219)	(4)	(5)%	(16)	(7)%
Income tax expense	—	(2)	(2)	(5)	(2)	*	(3)	(60)%
Net income attributable to noncontrolling interests	(1)	—	(3)	(1)	1	*	2	*
Net income (loss) attributable to partners	$ 81	$ (20)	$ 204	$ 169	$ 101	*	$ 35	21 %
Other data:								
Gross margin (c):								
Gathering and Processing	$ 364	$ 303	$ 1,049	$ 1,021	$ 61	20 %	$ 28	3 %
Logistics and Marketing	68	57	142	165	$ 11	19 %	(23)	(14)%
Total gross margin	$ 432	$ 360	$ 1,191	$ 1,186	$ 72	20 %	$ 5	— %
Non-cash commodity derivative mark-to-market	$ (13)	$ (59)	$ (79)	$ 1	$ 46	*	$ (80)	*
Natural gas wellhead (MMcf/d) (d)	4,881	4,460	4,715	4,508	421	9 %	207	5 %
NGL gross production (MBbls/d) (d)	439	376	416	365	63	17 %	51	14 %
NGL pipelines throughput (MBbls/d) (d)	616	462	575	447	154	33 %	128	29 %

* 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 and related costs. Segment gross margin for each segment consists of total operating revenues for that segment less purchases and related costs 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, 2018 vs. Three Months Ended September 30, 2017

Total Operating Revenues — Total operating revenues increased $704 million in 2018 compared to 2017 primarily as a result of the following:

- $677 million increase for our Logistics and Marketing segment primarily due to higher NGL and crude prices, higher gas and NGL sales volumes which impacts both sales and purchases, partially offset by lower natural gas prices, unfavorable commodity derivative activity and the implementation of ASC 606, and;

- $242 million increase for our Gathering and Processing segment due to higher NGL and crude prices, higher gas and NGL sales volumes due to increased drilling activity in our Eagle Ford system and the impact of Hurricane Harvey in 2017 in the South region, growth projects primarily related to our DJ Basin system in the North region and increased volumes in the Midcontinent and Permian regions. These increases were partially offset by lower natural gas prices, unfavorable commodity derivative activity and the implementation of ASC 606;

  These increases were partially offset by:

- $215 million change 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 gas and NGL sales volumes and higher commodity prices and the implementation of ASC 606.

Total Purchases — Total purchases increased $632 million in 2018 compared to 2017 primarily as a result of the following:

- $666 million increase for our Logistics and Marketing segment for the reasons discussed above, and;

- $181 million increase for our Gathering and Processing segment for the reasons discussed above;

  These increases were partially offset by:

- $215 million change 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 gas and NGL sales volumes and higher commodity prices and the implementation of ASC 606.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2018 compared to 2017 primarily as a result of increased reliability spending and planned maintenance spending associated with anticipated volume growth and from growth projects primarily related to our DJ Basin in the North Region.

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

Loss from Financing Activities — Loss from financing activities in 2018 represents a loss on redemption of senior notes.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2018 compared to 2017 primarily as a result of the expansion and volume ramp up of the Sand Hills NGL pipeline and higher volumes on the Southern Hills NGL pipeline in our Logistics and Marketing segment partially offset by a decrease from Discovery in our Gathering and Processing segment primarily due to lower production volumes from two offshore wells at Discovery.

Interest Expense - Interest expense decreased in 2018 compared to 2017 as a result of higher capitalized interest and lower average outstanding debt balances.

Net Income (Loss) Attributable to Partners — Net income (loss) attributable to partners increased in 2018 compared to 2017 for the reasons discussed above.

Gross Margin — Gross margin increased $72 million in 2018 compared to 2017 primarily as a result of the following:

- $61 million increase for our Gathering and Processing segment primarily related to higher commodity prices, increased volumes from increased drilling activity in our Eagle Ford system and the impact of Hurricane Harvey in 2017 in the South region, growth projects primarily related to our DJ Basin system in the North region and increased volumes in the Midcontinent region. These increases were partially offset by unfavorable commodity derivative activity.

- $11 million increase for our Logistics and Marketing segment primarily related to higher gas marketing margins due to favorable commodity spreads partially offset by unfavorable commodity derivative activity.

Nine Months Ended September 30, 2018 vs. Nine Months Ended September 30, 2017

Total Operating Revenues — Total operating revenues increased $1,090 million in 2018 compared to 2017 primarily as a result of the following:

- $1,165 million increase for our Logistics and Marketing segment primarily due to higher NGL and crude prices, higher gas and NGL sales volumes which impacts both sales and purchases, partially offset by lower natural gas prices, unfavorable commodity derivative activity and the implementation of ASC 606; and

- $214 million increase for our Gathering and Processing segment due to higher NGL and crude prices, higher gas and NGL sales volumes impacting both sales and purchases due to increased drilling activity in our Eagle Ford system and the impact of Hurricane Harvey in 2017 in the South region, growth projects primarily related to our DJ Basin system in the North region and increased volumes and better operational performance in our Midcontinent region. These increases were partially offset by lower natural gas prices, the sale of our Douglas gathering system in June 2017, unfavorable commodity derivative activity and the implementation of ASC 606;

  These increases were partially offset by:

- $289 million change 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 gas and NGL sales volumes and higher commodity prices and the implementation of ASC 606.

Total Purchases — Total purchases increased $1,085 million in 2018 compared to 2017 primarily as a result of the following:

- $1,188 million increase for our Logistics and Marketing segment for the reasons discussed above.

- $186 million increase for our Gathering and Processing segment for the reasons discussed above;

  These increases were partially offset by:

- $289 million change 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 gas and NGL sales volumes and higher commodity prices and the implementation of ASC 606;

Operating and Maintenance Expense — Operating and maintenance expense increased in 2018 compared to 2017 primarily as a result of increased reliability spending and planned maintenance spending associated with anticipated volume growth.

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

Other expense — Other expense in 2018 primarily represents the write-off of property, plant and equipment associated with asset rationalization. Other expense in 2017 primarily represents the write-off of property, plant and equipment associated with the expiration of a lease.

Gain on Sale of Assets, Net — The gain on sale in 2017 represents the sale of our Douglas gathering system.

Loss from Financing Activities — Loss from financing activities in 2018 represents a loss on redemption of senior notes.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2018 compared to 2017 primarily as a result of the expansion and volume ramp up of the Sand Hills NGL pipeline and higher volumes on the Southern Hills NGL pipeline in our Logistics and Marketing segment partially offset by a decrease from Discovery in our Gathering and Processing segment primarily due to lower production volumes from two offshore wells at Discovery.

Interest Expense - Interest expense decreased in 2018 compared to 2017 as a result of higher capitalized interest and lower average outstanding debt balances.

Net Income Attributable to Partners — Net income attributable to partners increased in 2018 compared to 2017 for the reasons discussed above.

Gross Margin — Gross margin increased $5 million in 2018 compared to 2017 primarily as a result of the following:

- $28 million increase for our Gathering and Processing segment primarily related to increased volumes from increased drilling activity in our Eagle Ford system and the impact of Hurricane Harvey in 2017 in the South region, growth projects primarily related to our DJ Basin system in the North region, increased volumes and improved operational performance in the Midcontinent region and higher commodity prices. These increases were partially offset by unfavorable commodity derivative activity, the sale of our Douglas gathering system in June 2017 and lower volumes in our Permian region due to weather impacting operations and operational factors;

These increases were partially offset by:

- $23 million decrease for our Logistics and Marketing segment primarily related to unfavorable commodity derivative activity, lower margins on wholesale propane and the expiration of a commercial arrangement, partially offset by higher gas marketing margins due to favorable commodity spreads.

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,	
	2018	2017	2018	2017
	(millions)			
DCP Sand Hills Pipeline, LLC	$ 64	$ 37	$ 170	$ 105
DCP Southern Hills Pipeline, LLC	21	10	50	34
Front Range Pipeline LLC	6	5	16	12
Texas Express Pipeline LLC	4	4	14	7
Mont Belvieu Enterprise Fractionator	3	3	10	10
Mont Belvieu 1 Fractionator	4	2	12	6
Discovery Producer Services LLC	1	14	4	59
Other	1	(1)	2	1
Total earnings from unconsolidated affiliates	$ 104	$ 74	$ 278	$ 234

Distributions received from unconsolidated affiliates were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(millions)			
DCP Sand Hills Pipeline, LLC	$ 76	$ 45	$ 187	$ 118
DCP Southern Hills Pipeline, LLC	24	16	60	47
Front Range Pipeline LLC	10	5	22	12
Texas Express Pipeline LLC	6	5	15	10
Mont Belvieu Enterprise Fractionator	1	2	7	8
Mont Belvieu 1 Fractionator	6	—	12	4
Discovery Producer Services LLC	8	19	20	68
Other	1	1	2	3
Total distributions from unconsolidated affiliates	$ 132	$ 93	$ 325	$ 270

Results of Operations — Gathering and Processing Segment

Operating Data

				Three Months Ended September 30, 2018		Nine Months Ended September 30, 2018	
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	14	4,000	1,395	1,246	97	1,219	92
Permian	15	16,500	1,390	930	111	907	108
Midcontinent	12	29,000	1,765	1,322	116	1,284	111
South	20	7,500	3,295	1,383	115	1,305	105
Total	61	57,000	7,845	4,881	439	4,715	416

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

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 2018 vs. 2017		Variance Nine Months 2018 vs. 2017	
	2018	2017	2018	2017	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(millions, except operating data)							
Operating revenues:								
Sales of natural gas, NGLs and condensate	$ 1,522	$ 1,249	$ 3,976	$ 3,562	$ 273	22 %	$ 414	12 %
Transportation, processing and other	118	145	327	424	(27)	(19)%	(97)	(23)%
Trading and marketing losses, net	(61)	(57)	(124)	(21)	(4)	(7)%	(103)	*
Total operating revenues	1,579	1,337	4,179	3,965	242	18 %	214	5 %
Purchases and related costs	(1,215)	(1,034)	(3,130)	(2,944)	181	18 %	186	6 %
Operating and maintenance expense	(175)	(154)	(492)	(469)	21	14 %	23	5 %
Depreciation and amortization expense	(87)	(85)	(258)	(256)	2	2 %	2	1 %
General and administrative expense	(6)	(2)	(12)	(15)	4	*	(3)	(20)%
Asset impairments	—	(48)	—	(48)	48	*	48	*
Other expense, net	(1)	—	(4)	(3)	1	*	1	*
Gain on sale of assets, net	—	—	—	34	—	*	(34)	*
Earnings from unconsolidated affiliates (a)	2	15	5	59	(13)	(87)%	(54)	(92)%
Segment net income	97	29	288	323	68	*	(35)	(11)%
Segment net income attributable to noncontrolling interests	(1)	—	(3)	(1)	1	*	2	*
Segment net income attributable to partners	$ 96	$ 29	$ 285	$ 322	$ 67	*	$ (37)	(11)%
Other data:								
Segment gross margin (b)	$ 364	$ 303	$ 1,049	$ 1,021	$ 61	20 %	$ 28	3 %
Non-cash commodity derivative mark-to-market	$ (21)	$ (51)	$ (49)	$ (4)	$ 30	59 %	$ (45)	*
Natural gas wellhead (MMcf/d) (c)	4,881	4,460	4,715	4,508	421	9 %	207	5 %
NGL gross production (MBbls/d) (c)	439	376	416	365	63	17 %	51	14 %

* 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 and related costs. 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 volume and NGL production.

Three Months Ended September 30, 2018 vs. Three Months Ended September 30, 2017

Total Operating Revenues — Total operating revenues increased $242 million in 2018 compared to 2017, primarily as a result of the following:

- $160 million increase attributable to higher NGL and crude prices, partially offset by lower natural gas prices, which impacted both sales and purchases, before the impact of derivative activity;

- $113 million increase primarily as a result of higher volumes due to increased drilling activity in our Eagle Ford system and the impact of Hurricane Harvey in 2017 in the South region, growth projects primarily related to our DJ Basin system in the North region and increased volumes in the Midcontinent and Permian regions, partially offset by $41 million due to the implementation of ASC 606, and

  These increases were partially offset by:

- $4 million decrease as a result of commodity derivative activity attributable to a $34 million increase in realized cash settlement losses partially offset by a decrease in unrealized commodity derivative losses of $30 million due to movements in forward prices of commodities in 2018; and

- $27 million decrease in transportation, processing and other primarily related to the implementation of ASC 606.

Purchases and Related Costs — Purchases and related costs increased $181 million in 2018 compared to 2017 as a result of increased gas and NGL sales volumes in our South, North, Midcontinent and Permian regions and higher NGL and crude prices, partially offset by lower natural gas prices.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2018 compared to 2017 primarily as a result of increased reliability spending and planned maintenance spending associated with anticipated volume growth and from growth projects primarily related to our DJ Basin in the North Region.

General and Administrative Expense — General and administrative expense increased in 2018 compared to 2017 primarily as a result of tax refunds received in 2017.

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

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates decreased in 2018 compared to 2017 primarily due to lower production volumes from two offshore wells at Discovery.

Segment Gross Margin — Segment gross margin increased $61 million in 2018 compared to 2017, primarily as a result of the following:

- $38 million increase as a result of higher commodity prices; and

- $27 million increase as a result of increased volumes from increased drilling activity in our Eagle Ford system and the impact of Hurricane Harvey in 2017 in the South region, growth projects primarily related to our DJ Basin system in the North region and increased volumes in the Midcontinent region;

  These increases were partially offset by:

- $4 million decrease as a result of commodity derivative activity as discussed above.

Total Wellhead — Natural gas wellhead increased in 2018 compared to 2017 reflecting higher volumes primarily from (i) general volume increases due to maximizing capacity utilization and growth projects within the North region and (ii) general volume increases due to increased drilling activity in our Eagle Ford system and the impact of Hurricane Harvey in 2017 in the South region and (iii) higher volumes in the Midcontinent region due to improved operational performance partially offset by (iv) lower production volumes from two offshore wells at Discovery in the South region.

NGL Gross Production — NGL gross production increased in 2018 compared to 2017 primarily as a result of (i) general volume increases due to maximizing capacity utilization and growth projects within the North region (ii) ethane recoveries in the Midcontinent, Permian and North regions (iii) general volume increases due to increased drilling activity in our Eagle Ford system in the South region and (iv) higher volumes in the Midcontinent region due to improved operational performance.

Nine Months Ended September 30, 2018 vs. Nine Months Ended September 30, 2017

Total Operating Revenues — Total operating revenues increased $214 million in 2018 compared to 2017, primarily as a result of the following:

- $211 million increase primarily as a result of higher volumes due to increased drilling activity in our Eagle Ford system in the South region, growth projects primarily related to our DJ Basin system in the North region and increased volumes and improved operational performance in the Midcontinent region, partially offset by the sale of our Douglas gathering system in June 2017 in our North region and $116 million due to the implementation of ASC 606; and

- $203 million increase attributable to higher NGL and crude prices, partially offset by lower natural gas prices, which impacted both sales and purchases, before the impact of derivative activity;

  These increases were partially offset by:

- $103 million decrease as a result of commodity derivative activity attributable to an increase in unrealized commodity derivative losses of $45 million and a $58 million increase in realized cash settlement losses due to movements in forward prices of commodities in 2018, and

- $97 million decrease in transportation, processing and other primarily related to the implementation of ASC 606.

Purchases and Related Costs — Purchases and related costs increased $186 million in 2018 compared to 2017 as a result of increased gas and NGL sales volumes in our South, Midcontinent and North regions and higher NGL and crude prices, partially offset by lower natural gas prices.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2018 compared to 2017 primarily as a result of increased reliability spending and planned maintenance spending associated with anticipated volume growth.

General and Administrative Expense — General and administrative expense decreased in 2018 compared to 2017 primarily as a result of insurance premium recoveries.

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

Gain on Sale of Assets, Net — The gain on sale in 2017 represents the sale of our Douglas gathering system.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates decreased in 2018 compared to 2017 primarily due to lower production volumes from two offshore wells at Discovery.

Segment Gross Margin — Segment gross margin increased $28 million in 2018 compared to 2017, primarily as a result of the following:

- $91 million increase as a result of increased volume from increased drilling activity in our Eagle Ford system and the impact of Hurricane Harvey in 2017 in the South region, growth projects primarily related to our DJ Basin system in the North region and increased volumes and improved operational performance in the Midcontinent region; and

- $68 million increase as a result of higher commodity prices;

  These increases were partially offset by:

- $103 million decrease as a result of commodity derivative activity as discussed above;

- $15 million decrease primarily as a result of the sale of our Douglas gathering system in June 2017; and

- $13 million decrease primarily as a result of lower volumes due to operational factors and weather impacting operations in the Permian region.

Total Wellhead — Natural gas wellhead increased in 2018 compared to 2017 reflecting higher volumes primarily from (i) general volume increases due to maximizing capacity utilization and growth projects within the North region, (ii) general volume increases due to increased drilling activity in our Eagle Ford system and the impact of Hurricane Harvey in 2017 in the South region and (iii) higher volumes in the Midcontinent region due to improved operational performance partially offset by (iv) lower production volumes from two offshore wells at Discovery in the South region (v) lower volumes in the Permian region due to operational factors and (vi) the sale of our Douglas gathering system within our North region.

NGL Gross Production — NGL gross production increased in 2018 compared to 2017 primarily as a result of (i) general volume increases due to maximizing capacity utilization and growth projects within the North region, (ii) ethane recoveries in the Midcontinent, Permian and North regions (iii) general volume increases due to increased drilling activity in the South region and (iv) higher volumes in the Midcontinent region due to improved operational performance.

Results of Operations — Logistics and Marketing Segment

Operating Data

				Three Months Ended September 30, 2018		Nine Months Ended September 30, 2018	
System	**Approximate System Length (Miles)**	**Fractionators**	**Approximate Throughput Capacity (MBbls/d) (a)**	**Pipeline Throughput (MBbls/d) (a)**	**Fractionator Throughput (MBbls/d) (a)**	**Pipeline Throughput (MBbls/d) (a)**	**Fractionator Throughput (MBbls/d) (a)**
Sand Hills pipeline	1,400	—	283	280	—	265	—
Southern Hills pipeline	950	—	117	99	—	87	—
Front Range pipeline	450	—	50	45	—	42	—
Texas Express pipeline	600	—	28	22	—	19	—
Other NGL pipelines (a)	1,200	—	241	170	—	162	—
Mont Belvieu fractionators	—	2	60	—	60	—	59
Total	4,600	2	779	616	60	575	59

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

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 2018 vs. 2017		Variance Nine Months 2018 vs. 2017	
	2018	2017	2018	2017	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(millions, except operating data)							
Operating revenues:								
Sales of natural gas, NGLs and condensate	$ 2,570	$ 1,882	$ 6,756	$ 5,515	$ 688	37 %	$ 1,241	23 %
Transportation, processing and other	15	17	45	50	(2)	(12)%	(5)	(10)%
Trading and marketing gains (losses), net	5	14	(40)	31	(9)	(64)%	(71)	*
Total operating revenues	2,590	1,913	6,761	5,596	677	35 %	1,165	21 %
Purchases and related costs	(2,522)	(1,856)	(6,619)	(5,431)	666	36 %	1,188	22 %
Operating and maintenance expense	(14)	(9)	(36)	(31)	5	56 %	5	16 %
Depreciation and amortization expense	(5)	(4)	(11)	(11)	1	25 %	—	— %
General and administrative expense	(3)	(3)	(9)	(8)	—	— %	1	13 %
Other expense, net	—	(1)	(2)	(12)	(1)	*	(10)	(83)%
Earnings from unconsolidated affiliates (a)	102	59	273	175	43	73 %	98	56 %
Segment net income attributable to partners	$ 148	$ 99	$ 357	$ 278	$ 49	49 %	$ 79	28 %
Other data:								
Segment gross margin (b)	$ 68	$ 57	$ 142	$ 165	$ 11	19 %	$ (23)	(14)%
Non-cash commodity derivative mark-to-market	$ 8	$ (8)	$ (30)	$ 5	16	*	$ (35)	*
NGL pipelines throughput (MBbls/d) (c)	616	462	575	447	154	33 %	128	29 %

(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 and related costs. 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 throughput volume.

Three Months Ended September 30, 2018 vs. Three Months Ended September 30, 2017

Total Operating Revenues — Total operating revenues increased $677 million in 2018 compared to 2017, primarily as a result of the following:

- $445 million increase as a result of higher NGL and crude prices, partially offset by lower natural gas prices, which impacted both sales and purchases, before the impact of derivative activity, and;
- $243 million increase attributable to higher gas and NGL sales volumes, which impacted both sales and purchases, offset by $41 million due to the implementation of ASC 606;

These increases were partially offset by:

- $9 million decrease as a result of commodity derivative activity attributable to a $25 million increase in realized cash settlement losses partially offset by an increase in unrealized commodity derivative gains of $16 million due to movements in forward prices of commodities in 2018;

Purchases and Related Costs — Purchases and related costs increased $666 million in 2018 compared to 2017, primarily as a result of higher NGL and crude prices and higher gas and NGL sales volumes, partially offset by lower natural gas prices and the implementation of ASC 606.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2018 compared to 2017 primarily as a result of increased reliability spending and planned maintenance spending associated with anticipated volume growth.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2018 compared to 2017 primarily as a result of higher throughput volumes on Sand Hills due to ongoing capacity expansions and higher volumes on the Southern Hills NGL pipeline.

Segment Gross Margin — Segment gross margin increased $11 million in 2018 compared to 2017, primarily as a result of the following:

- $20 million increase in gas marketing margins due to favorable commodity spreads;

  These increases are partially offset by;

- $9 million decrease as a result of commodity derivative activity discussed above;

NGL Pipelines Throughput — NGL pipelines throughput increased in 2018 compared to 2017 primarily as a result of higher throughput volumes on Sand Hills due to ongoing capacity expansions on the Sand Hills pipeline and higher throughput volumes on Southern Hills primarily due to ethane recovery.

Nine Months Ended September 30, 2018 vs. Nine Months Ended September 30, 2017

Total Operating Revenues — Total operating revenues increased $1,165 million in 2018 compared to 2017, primarily as a result of the following:

- $843 million increase as a result of higher NGL and crude prices, partially offset by lower natural gas prices, which impacted both sales and purchases, before the impact of derivative activity, and;

- $398 million increase attributable to higher gas and NGL sales volumes, which impacted both sales and purchases, offset by $116 million due to the implementation of ASC 606;

  These increases were partially offset by:

- $71 million decrease as a result of commodity derivative activity attributable to a $36 million increase in realized cash settlement losses and an increase in unrealized commodity derivative losses of $35 million due to movements in forward prices of commodities in 2018;

- $5 million decrease in transportation, processing and other primarily related to the expiration of a commercial arrangement in our wholesale propane business;

Purchases and related costs — Purchases and related costs increased $1,188 million in 2018 compared to 2017, primarily as a result of higher NGL and crude prices and higher gas and NGL sales volumes, partially offset by lower natural gas prices and the implementation of ASC 606.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2018 compared to 2017 primarily as a result of increased reliability spending and planned maintenance spending associated with anticipated volume growth.

Other Expense, net — Other expense in 2017 represents the write-off of property, plant and equipment associated with the expiration of a lease.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2018 compared to 2017 primarily as a result of higher throughput volumes on Sand Hills due to ongoing capacity expansions, higher volumes on the Southern Hills NGL pipeline and accelerated recognition of revenues at Texas Express.

Segment Gross Margin — Segment gross margin decreased $23 million in 2018 compared to 2017, primarily as a result of the following:

- $71 million decrease as a result of commodity derivative activity discussed above, and;

- $2 million decrease as a result of lower margins and the expiration of a commercial arrangement in our wholesale propane business, partially offset by higher throughput volumes;

  These decreases are partially offset by;

- $50 million increase in gas marketing margins due to favorable commodity spreads.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2018 compared to 2017 primarily as a result of higher throughput volumes on Sand Hills due to ongoing capacity expansions on the Sand Hills pipeline and higher throughput volumes on Southern Hills primarily due to ethane recovery.

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;
- debt offerings;
- issuances of additional common units, preferred units or other securities;
- borrowings under term loans, securitization agreements or other credit facilities; and
- letters of credit.

We anticipate our more significant uses of resources to include:

- quarterly distributions to our common unitholders and General Partner, and distributions to our preferred unitholders;
- 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, 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.

Accounts Receivable Securitization Facility — In August 2018, we entered into the Securitization Facility that provides up to $200 million of borrowing capacity through August 2019 at LIBOR market index rates plus a margin. As of September 30, 2018, we had $200 million of outstanding borrowings on the Securitization Facility.

Senior Notes — On July 17, 2018, we issued $500 million of 5.375% Senior Notes due July 2025, unless redeemed prior to maturity. We received proceeds of $495 million, net of underwriters' fees, related expenses and unamortized discounts which we used to redeem our $450 million 9.750% Senior Notes due March 2019. Interest on the notes will be paid semi-annually in arrears on January 15 and July 15 of each year, commencing January 15, 2019.

Credit Agreement — As of September 30, 2018, we had unused borrowing capacity of $1,242 million, net of $13 million of letters of credit, and $145 million of outstanding borrowings under the Credit Agreement. Our cost of borrowing under the Credit Agreement is determined by a ratings-based pricing grid. As of November 1, 2018, we had approximately $1,220 million of unused borrowing capacity under the Credit Agreement, net of $13 million of letters of credit.

Issuance of Units — In November 2017, we filed a shelf registration statement with the SEC that became effective upon filing and allows us to issue an indeterminate amount of common units, preferred units, and debt securities. During the nine months ended September 30, 2018, we issued our Series B Preferred Units and our 5.375% Senior Notes due July 2025 under this registration statement.

On October 4, 2018, we issued 4,000,000 of our Series C Preferred Units representing limited partnership interests at a price of $25 per unit. On October 19, 2018, we issued an additional 400,000 Series C Preferred Units which represented the partial exercise of the underwriters' option to purchase additional Series C Preferred Units. We used the net proceeds of $106 million from the issuance of the Series C Preferred Units for general partnership purposes including funding capital expenditures and the repayment of outstanding indebtedness under our revolving credit facility.

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 at-the-market program. During the nine months ended September 30, 2018, we did not issue any common units pursuant to this registration statement, and $750 million remained available for future sales.

Commodity Swaps and Collateral — 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. 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 and the Securitization Facility, 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 $807 million and $166 million as of September 30, 2018 and December 31, 2017, respectively. The change in working capital is primarily attributable to current maturities of long-term debt. We had a net derivative working capital deficit of $100 million and $46 million as of September 30, 2018 and December 31, 2017, respectively.

As of September 30, 2018, we had $1 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,	
	2018	2017
	(millions)	
Net cash provided by operating activities	$ 541	$ 684
Net cash used in investing activities	$ (690)	$ (198)
Net cash used in financing activities	$ (6)	$ (175)

Nine Months Ended September 30, 2018 vs. Nine Months Ended September 30, 2017

Operating Activities - Net cash provided by operating activities decreased $143 million in 2018 compared to the same period in 2017. 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. In addition, we received $11 million more of cash distributions in excess of earnings from unconsolidated affiliates during the nine months ended September 30, 2018 compared to the same period in 2017. For additional information regarding fluctuations in our earnings and distributions from unconsolidated affiliates, please read "Results of Operations".

*Investing Activitie*s - Net cash used in investing activities increased $492 million in 2018 compared to the same period in 2017 primarily as a result of higher capital expenditures used for construction of the Mewbourn 3 plant and O'Connor 2 plant, and higher investments in unconsolidated affiliates for the capacity expansion of the Sand Hills pipeline and investment in Gulf Coast Express, offset by proceeds from the sale of our Douglas gathering system in 2017.

Financing Activities - Net cash used in financing activities decreased $169 million in 2018 compared to the same period in 2017 primarily as a result of net proceeds from long-term debt including $200 million from the Securitization Facility and proceeds from the issuance of Series B Preferred Units, partially offset by higher distributions paid to limited partners and the general partner due to a higher number of outstanding common units and general partner units following our acquisition of the DCP Midstream business in 2017 and distributions paid to preferred unitholders. We also received cash from the acquisition of the DCP Midstream business in 2017.

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. Our 2018 plan includes maintenance capital expenditures of between $100 million and $120 million, and expansion capital expenditures between $825 million and $900 million associated with approved projects. Expansion capital expenditures include the construction of the Mewbourn 3 plant, and O'Connor 2 expansion in our DJ Basin system, and the capacity expansions of the Sand Hills pipeline, and the construction of the Gulf Coast Express 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 for the nine months ended September 30, 2018 and 2017:

	Nine Months Ended September 30, 2018			Nine Months Ended September 30, 2017		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
	(millions)					
Our portion	$ 69	$ 365	$ 434	$ 64	$ 191	$ 255
Noncontrolling interest portion and reimbursable projects (a)	(2)	(4)	(6)	1	2	3
Total	$ 67	$ 361	$ 428	$ 65	$ 193	$ 258

(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 $265 million and $70 million during the nine months ended September 30, 2018 and 2017, 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 equity securities 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 common unitholders and general partner of $503 million and $390 million during the nine months ended September 30, 2018 and 2017, respectively. Distributions paid during the nine months ended September 30, 2018 reflect the distribution of $40 million of IDR givebacks to the IDR holders, in conjunction with the quarterly distribution, that were previously withheld in 2017 under the amended Partnership Agreement. 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. During the nine months ended September 30, 2018, no IDR giveback was withheld from the distribution declared.

In accordance with our amended Partnership Agreement, on October 23, 2018, we announced that the board of directors of the General Partner declared a quarterly distribution on our common units of $0.78 per common unit. This distribution per common unit remains unchanged from the previous quarter and the third quarter of 2017. The distribution will be paid on November 14, 2018 to unitholders of record on November 2, 2018.

On the same date, we announced that the board of directors of the General Partner declared a semi-annual and quarterly distribution on our Series A Preferred Units and B Preferred Units of $36.8750 and $0.4922 per unit, respectively. The distributions will be paid on December 17, 2018 to unitholders of record on December 3, 2018.

On the same date, we announced that the board of directors of the General Partner declared an initial quarterly distribution on our Series C Preferred Units of $0.5576 per Series C Preferred Unit, which includes the distribution attributable to the partial-period from and including the original issue date of October 4, 2018. The distribution will be paid on January 15, 2019 to unitholders of record on January 2, 2019.

Total Contractual Cash Obligations

A summary of our total contractual cash obligations as of September 30, 2018, was as follows:

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
			(millions)		
Debt (a)	$ 7,906	$ 566	$ 1,548	$ 1,207	$ 4,585
Operating lease obligations	122	29	46	28	19
Purchase obligations (b)	4,802	1,247	1,116	1,044	1,395
Other long-term liabilities (c)	146	—	8	20	118
Total	$ 12,976	$ 1,842	$ 2,718	$ 2,299	$ 6,117

(a) Includes interest payments on debt securities that have been issued. These interest payments are $241 million, $448 million, $357 million, and $2,085 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, 2018. 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, 2018 condensed consolidated balance sheet. The table above excludes non-cash obligations as well as $32 million of Executive Deferred Compensation Plan contributions and $10 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, 2018, 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 and related costs, 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, net cash provided by operating activities or any other measure of financial performance presented in accordance with 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, net cash provided by 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 segment 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, less income attributable to preferred units, 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. Income attributable to preferred units represent cash distributions earned by the Series A Preferred Units. Cash distributions to be paid to the holders of the Series A, Series B and Series C Preferred Units (collectively the "Preferred Limited Partnership Units") assuming a distribution is declared by our board of directors, are not available to common unit holders. 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,	
	2018	2017	2018	2017
Reconciliation of Non-GAAP Measures	(millions)			
Reconciliation of net income attributable to partners to gross margin:				
Net income (loss) attributable to partners	$ 81	$ (20)	$ 204	$ 169
Interest expense	69	73	203	219
Income tax expense	—	2	2	5
Operating and maintenance expense	196	168	543	513
Depreciation and amortization expense	98	94	289	282
General and administrative expense	70	69	199	202
Asset impairments	—	48	—	48
Loss from financing activities	19	—	19	—
Other expense, net	2	—	7	15
Earnings from unconsolidated affiliates	(104)	(74)	(278)	(234)
Gain on sale of assets, net	—	—	—	(34)
Net income attributable to noncontrolling interests	1	—	3	1
Gross margin	$ 432	$ 360	$ 1,191	$ 1,186
Non-cash commodity derivative mark-to-market (a)	$ (13)	$ (59)	$ (79)	$ 1
Reconciliation of segment net income attributable to partners to segment gross margin:				
Gathering and Processing segment:				
Segment net income attributable to partners	$ 96	$ 29	$ 285	$ 322
Operating and maintenance expense	175	154	492	469
Depreciation and amortization expense	87	85	258	256
General and administrative expense	6	2	12	15
Asset impairments	—	48	—	48
Other expense, net	1	—	4	3
Earnings from unconsolidated affiliates	(2)	(15)	(5)	(59)
Gain on sale of assets, net	—	—	—	(34)
Net income attributable to noncontrolling interests	1	—	3	1
Segment gross margin	$ 364	$ 303	$ 1,049	$ 1,021
Non-cash commodity derivative mark-to-market (a)	$ (21)	$ (51)	$ (49)	$ (4)
Logistics and Marketing segment:				
Segment net income attributable to partners	$ 148	$ 99	$ 357	$ 278
Operating and maintenance expense	14	9	36	31
Depreciation and amortization expense	5	4	11	11
General and administrative expense	3	3	9	8
Other expense, net	—	1	2	12
Earnings from unconsolidated affiliates	(102)	(59)	(273)	(175)
Segment gross margin	$ 68	$ 57	$ 142	$ 165
Non-cash commodity derivative mark-to-market (a)	$ 8	$ (8)	$ (30)	$ 5

(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,	
	2018	2017	2018	2017
	(millions)			
Reconciliation of net income attributable to partners to adjusted segment EBITDA:				
Gathering and Processing segment:				
Segment net income attributable to partners	$ 96	$ 29	$ 285	$ 322
Non-cash commodity derivative mark-to-market	21	51	49	4
Depreciation and amortization expense, net of noncontrolling interest	85	85	257	256
Asset impairments	—	48	—	48
Gain on sale of assets, net	—	—	—	(34)
Distributions from unconsolidated affiliates, net of earnings	7	6	16	10
Other expense	1	1	4	4
Adjusted segment EBITDA	$ 210	$ 220	$ 611	$ 610
Logistics and Marketing segment:				
Segment net income attributable to partners (a)	$ 148	$ 99	$ 357	$ 278
Non-cash commodity derivative mark-to-market	(8)	8	30	(5)
Depreciation and amortization expense, net of noncontrolling interest	5	4	11	11
Distributions from unconsolidated affiliates, net of earnings	21	13	31	26
Other expense	—	—	—	9
Adjusted segment EBITDA	$ 166	$ 124	$ 429	$ 319

(a) There were no lower of cost or market adjustments for the three and nine months ended September 30, 2018 and 2017.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Critical Accounting Policies and Estimates within Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in our Annual Report on Form 10-K for the year ended December 31, 2017 and Note 2 of the Notes to Consolidated Financial Statements in “Financial Statements and Supplementary Data” included as Item 8 in our Annual Report on Form 10-K for the year ended December 31, 2017. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three and nine months ended September 30, 2018 are the same as those described in our Annual Report on Form 10-K for the year ended December 31, 2017. Certain information and note disclosures normally included in our annual financial statements prepared in accordance with GAAP have been condensed or omitted from the interim financial statements included in this Quarterly Report on Form 10-Q pursuant to the rules and regulations of the SEC, although we believe that the disclosures made are adequate to make the information not misleading. The unaudited condensed consolidated financial statements and other information included in this Quarterly Report on Form 10-Q should be read in conjunction with the audited consolidated financial statements and notes thereto in our Annual Report on Form 10-K for the year ended December 31, 2017.

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, 2017.

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 1, 2018 were as follows:

Commodity Swaps

Period	Commodity	Notional Volume - Short Positions	Reference Price	Price Range
October 2018 — December 2018	NGLs	(25,930) Bbls/d (c)	Mt.Belvieu (b)	$.32-$.97/Gal
January 2019 — December 2019	NGLs	(11,851) Bbls/d (c)	Mt.Belvieu (b)	$.31-$1.10/Gal
October 2018 — February 2019	Crude Oil	(9,356) Bbls/d (c)	NYMEX crude oil futures (a)	$51.26-$64.87/Bbl
March 2019 — February 2020	Crude Oil	(3,781) Bbls/d (c)	NYMEX crude oil futures (a)	$57.12-$65.32/Bbl

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

Our sensitivities for 2018 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 2018, 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	$	8
Crude oil prices	$	1.00	Barrel	$	2
NGL prices	$	0.01	Gallon	$	4

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	$	—
Crude oil prices	$	1.00	Barrel	$	3
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 2020.

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. Additionally, the level of NGL export demand may also have an impact on prices. 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, 2018:

Inventory

Period ended	Commodity	Notional Volume - Long Positions		Fair Value (millions)		Weighted Average Price
September 30, 2018	Natural Gas	5,554,889	MMBtu	$	16	$2.83/MMBtu

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions		Fair Value (millions)		Price Range
October 2018-February 2019	Natural Gas	(14,795,000)	MMBtu	$	(2)	$2.80-$3.18/MMBtu
October 2018	Natural Gas	7,720,000	MMBtu	$	1	$2.78-$3.05/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 (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, 2018, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of September 30, 2018, 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, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

Item 1. ***Legal Proceedings***

The information provided in “Commitments and Contingent Liabilities,” included in Note 19 in the 2017 audited consolidated financial statements and notes thereto included as Note 19 of Item 8 in the Annual Report on Form 10-K for the year ended December 31, 2017 and in Note 15 of Part I of this Quarterly Report on Form 10-Q is incorporated herein 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, 2017. 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, 2017. There are no material changes to the risk factors described in our Annual Report on Form 10-K for the year ended December 31, 2017, except as described below.

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, 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 or we may be required to find alternative markets and arrangements for our natural gas and NGLs.

The natural gas we gather, compress, treat, process, transport, sell and store, or the NGLs we produce, fractionate, transport, sell and store, are delivered into pipelines for further delivery to end-users, including fractionation facilities. If these pipelines, storage and fractionation facilities cannot, or will not, accept delivery of the gas or NGLs due to capacity constraints or changes in interstate pipeline gas quality specifications, we may be forced to limit or stop the flow of gas or NGLs through our pipelines and processing, treating, and fractionation facilities. We have long-term arrangements with facilities to fractionate our NGL production; however, due to increased production and growth of our logistics and marketing business, our contracted capacity for fractionation may not be sufficient to handle all of our projected production and the availability of additional fractionation capacity may be limited. However, current and planned fractionation facilities may experience delays in construction, significant mechanical problems at existing facilities, or become unavailable to us due to unforeseen circumstances. As a result, we may be required to find alternative markets and arrangements for our production and for fractionation, and such alternative markets and arrangements may not be available on favorable terms, or at all. Additionally, capacity constraints may impact production volumes from our producer customers and/or transportation volumes from our third-party NGL customers if there is insufficient fractionation or storage capacity to handle all of their projected volumes. Any number of factors beyond our control could cause such interruptions or constraints, including fully utilized capacity, necessary and scheduled maintenance, or unexpected damage to the pipelines. Because our revenues and net operating margins depend upon (i) the volumes of natural gas we process, gather and transmit, (ii) the throughput of NGLs through our transportation, fractionation and storage facilities and (iii) the volume of natural gas we gather and transport, any reduction of volumes could adversely affect our operations and cash flows available for distribution to our unitholders.

Colorado ballot Proposition 112, if approved by voters in November 2018, would likely have a material adverse impact on new oil and gas development in the state and could reduce the demand for our services in the state.

The Colorado Secretary of State has approved a citizen-initiated ballot measure, referred to as Proposition 112, for inclusion on the statewide voter ballot in November 2018. Proposition 112 seeks to amend the Colorado Revised Statutes to increase setback distances by requiring that all new oil and gas development on non-federal lands (i.e. state and private land) be located at least 2,500 feet away from certain occupied structures, including homes, schools and hospitals, as well as certain defined “vulnerable areas,” including playgrounds, permanent sports fields, public parks and open spaces, public drinking water sources, reservoirs, lakes, rivers, perennial and intermittent streams, and creeks. In contrast, rules adopted and enforced by the Colorado Oil and Gas Conservation Commission (“***COGCC***”) currently require that wells and production facilities be located at least 500 feet away from homes and 1,000 feet away from certain defined high occupancy building units, including schools, subject to certain exceptions. The term “oil and gas development” is broadly defined under Proposition 112 to include oil and gas exploration, drilling, hydraulic fracturing, flowlines, production and processing activities, including the gas processing and potentially the gathering and field compression services we provide to our oil and gas customers in the state. Under Proposition 112, state and local governments would be allowed to designate vulnerable areas beyond those that are defined in the measure, but the proposal provides no additional guidance on procedures or any limitations with respect to such designations. Proposition 112 further provides that the state or a local government may increase the setback to a distance larger than 2,500 feet, again without any defined procedure, limitations, or governing standards. Proposition 112 would take effect upon official certification of election results, is self-executing, and will apply to new oil and gas development (which includes the reentry of an oil or gas well previously plugged or abandoned) that is permitted on or after the date of certification, but is not expected to apply to previously permitted wells, including drilled but uncompleted wells.

The COGCC conducted a study in 2018 and determined that, if Proposition 112 were approved by state voters, an estimated 54% of Colorado's total land surface would be unavailable for new oil and gas development, or 85% of all non-federal lands. Focusing on Weld County, located in the DJ Basin, the 2018 COGCC study determined that approval and adoption of Proposition 112 would preclude new oil and gas development on approximately 78% of the total land surface and 85% of the non-federal land surface in the county. If Colorado voters approve Proposition 112 in November 2018, then we may be limited in our ability, and there may be less need, to develop new gas processing, gathering, and field compression facilities, and our customers in the state, from whom we currently derive a significant portion of our consolidated revenue, may experience material curtailment in the permitting of new oil and gas development. Any such curtailments on new oil and gas development, would, as production from existing and previously permitted wells depletes, lead to a reduction in demand for our gathering, processing, and transportation services in the state, which reduction, over time, may be material.

Item 6. ***Exhibits, Financial Statement Schedules***

Exhibit Number		Description
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, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 17, 2017).
3.3	*	Fourth Amended and Restated Agreement of Limited Partnership of DCP Midstream, LP dated October 4, 2018 (attached as Exhibit 3.1 to DCP Midstream, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on October 4, 2018).
4.1	*	Form of Unit Certificate for 7.95% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (attached as Exhibit 4.1 to DCP Midstream, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on October 4, 2018).
4.2	*	Seventh Supplemental Indenture, dated as of July 17, 2018, by and among DCP Midstream Operating, LP, DCP Midstream, LP, and The Bank of New York Mellon Trust Company, N.A. (attached as Exhibit 4.3 to DCP Midstream, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on July 17, 2018).
4.3	*	Form of 5.375% Notes due 2025 (included in Exhibit 4.2 hereto).
10.1	*	Receivables Financing Agreement, dated August 13, 2018, among DCP Receivables LLC, as borrower, the Partnership, as initial servicer, the lenders, LC participants and group agents that are parties thereto from time to time, PNC Bank National Association, as Administrative Agent and LC Bank and PNC Capital Markets LLC, as Structuring Agent (attached as Exhibit 10.1 to DCP Midstream, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 14, 2018).
10.2	*	Receivables Sale and Contribution Agreement, dated August 13, 2018, between the originators from time to time party thereto and DCP Receivables LLC (attached as Exhibit 10.2 to DCP Midstream, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 14, 2018).
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, 2018, formatted in XBRL: (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Comprehensive Income, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Consolidated Statements of Changes in Equity, and (vi) the Notes to the Condensed Consolidated Financial Statements.

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

SIGNATURES

Pursuant to the requirements of 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 6, 2018	By:	/s/ Wouter T. van Kempen	
		Name:	Wouter T. van Kempen
		Title:	President and Chief Executive Officer (Principal Executive Officer)
Date: November 6, 2018	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 and
Ratio of Earnings to Combined Fixed Charges and Preferred Unit Distributions

	Nine Months Ended September 30,	Year Ended December 31,				
	2018	2017	2016 (a)	2015 (a)	2014 (a)	2013 (a)
			(millions)			
Earnings from continuing operations before fixed charges:						
Pretax (loss) income from continuing operations attributable to partners before earnings from unconsolidated affiliates	$ (72)	$ (72)	$ (148)	$ (1,157)	$ 476	$ 554
Fixed charges	218	298	324	355	322	290
Amortization of capitalized interest	6	7	7	7	6	5
Distributed earnings from unconsolidated affiliates	278	303	282	184	82	35
Less:						
Capitalized interest	(14)	(7)	(1)	(32)	(34)	(40)
Earnings from continuing operations before fixed charges	$ 416	$ 529	$ 464	$ (643)	$ 852	$ 844
Fixed charges:						
Interest expense, net of capitalized interest	198	282	300	310	277	239
Capitalized interest	14	7	1	32	34	40
Estimate of interest within rental expense	1	2	2	2	1	2
Amortization of deferred loan costs	5	7	21	11	10	9
Total fixed charges	$ 218	$ 298	$ 324	$ 355	$ 322	$ 290
Distributions to Series A Preferred Units	28	4	—	—	—	—
Distributions to Series B Preferred Units	5	—	—	—	—	—
Total combined fixed charges and preferred unit distributions	$ 251	$ 302	$ 324	$ 355	$ 322	$ 290
Ratio of earnings to fixed charges (b)	1.91	1.78	1.43	—	2.65	2.91
Ratio of earnings to combined fixed charges and preferred unit distributions (c)	1.66	1.75	—	—	—	—

(a) The financial information for the the years ended December 31, 2016, 2015, 2014 and 2013 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.
(c) No preferred units were outstanding for the years ended December 31, 2016, 2015, 2014, and 2013. No historical ratios of earnings to combined fixed charges and preferred distributions are presented for these years.

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 period ended September 30, 2018;

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 6, 2018

/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 period ended September 30, 2018;

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 6, 2018

/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 period ended September 30, 2018, 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 6, 2018

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 period ended September 30, 2018, 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 6, 2018

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.