DCP Midstream, LP
Form 10-Q
August 08, 2018
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 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 ý No ¨

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ý	Accelerated filer	¨	¨

Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨ Emerging growth 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 ý

As of August 3, 2018, there were 143,309,828 common units representing limited partner interests outstanding.

DCP MIDSTREAM, LP
FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2018
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GLOSSARY OF TERMS

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

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

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in Item 1A. "Risk Factors" in this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2017, including the following risks and uncertainties:

- the extent of changes in commodity prices and the demand for our products and services, our ability to effectively limit a portion of the adverse impact of potential changes in commodity prices through derivative financial instruments, and the potential impact of price, and of producers’ access to capital on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;
- the demand for crude oil, residue gas and NGL products;
- the level and success of drilling and quality of production volumes around our assets and our ability to connect supplies to our gathering and processing systems, as well as our residue gas and NGL infrastructure;
- volatility in the price of our common units;
- general economic, market and business conditions;
- our ability to continue the safe and reliable operation of our assets;
- our ability to construct and start up facilities on budget and in a timely fashion, which is partially dependent on obtaining required construction, environmental and other permits issued by federal, state and municipal governments, or agencies thereof, the availability of specialized contractors and laborers, and the price of and demand for materials;
- our ability to access the debt and equity markets and the resulting cost of capital, which will depend on general market conditions, our financial and operating results, inflation rates, interest rates, our ability to comply with the covenants in our $1.4 billion unsecured revolving Credit Agreement (the "Credit Agreement") 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, 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;
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses; and

- the amount of natural gas we gather, compress, treat, process, transport, store and sell, or the NGLs we produce, fractionate, transport, store and sell, may be reduced if the pipelines and storage and fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the natural gas or NGLs.

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

PART I
Item 1. Financial Statements (Unaudited)
DCP MIDSTREAM, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2018	December 31, 2017
ASSETS	(millions)	
Current assets:		
Cash and cash equivalents	$4	$156
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $6 and $8 million, respectively	824	773
Affiliates	189	191
Other	16	17
Inventories	47	68
Unrealized gains on derivative instruments	45	30
Collateral cash deposits	138	75
Other	19	12
Total current assets	1,282	1,322
Property, plant and equipment, net	9,080	8,983
Goodwill	231	231
Intangible assets, net	101	106
Investments in unconsolidated affiliates	3,165	3,050
Unrealized gains on derivative instruments	8	3
Other long-term assets	174	183
Total assets	$14,041	$13,878
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$968	$989
Affiliates	112	68
Other	27	19
Current maturities of long-term debt	325	—
Unrealized losses on derivative instruments	141	76
Accrued interest	71	71
Accrued taxes	60	58
Accrued wages and benefits	42	65
Capital spending accrual	33	39
Other	108	103
Total current liabilities	1,887	1,488
Long-term debt	4,510	4,707
Unrealized losses on derivative instruments	29	15
Deferred income taxes	29	29
Other long-term liabilities	233	201
Total liabilities	6,688	6,440
Commitments and contingent liabilities (see note 14)		
Equity:		
Series A preferred limited partners (500,000 preferred units authorized, issued and outstanding, respectively)	488	491

Series B preferred limited partners (6,450,000 preferred units authorized, issued and outstanding, respectively)	157	—
General partner	109	154
Limited partners (143,309,828 and 143,309,828 common units authorized, issued and outstanding, respectively)	6,577	6,772
Accumulated other comprehensive loss	(8)	(9)
Total partners’ equity	7,323	7,408
Noncontrolling interests	30	30
Total equity	7,353	7,438
Total liabilities and equity	$ 14,041	$ 13,878

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, NGLs and condensate	$1,849	$1,494	$3,593	$3,138
Sales of natural gas, NGLs and condensate to affiliates	408	278	733	567
Transportation, processing and other	127	155	238	312
Trading and marketing (losses) gains, net	(67)	22	(108)	53
Total operating revenues	2,317	1,949	4,456	4,070
Operating costs and expenses:				
Purchases and related costs	1,703	1,419	3,307	2,978
Purchases and related costs from affiliates	225	138	390	266
Operating and maintenance expense	185	178	347	345
Depreciation and amortization expense	97	94	191	188
General and administrative expense	70	71	129	133
Other expense, net	3	5	5	15
Gain on sale of assets, net	—	(34)	—	(34)
Total operating costs and expenses	2,283	1,871	4,369	3,891
Operating income	34	78	87	179
Earnings from unconsolidated affiliates	96	86	174	160
Interest expense, net	(67)	(73)	(134)	(146)
Income before income taxes	63	91	127	193
Income tax expense	(1)	(2)	(2)	(3)
Net income	62	89	125	190
Net income attributable to noncontrolling interests	(1)	(1)	(2)	(1)
Net income attributable to partners	61	88	123	189
Series A preferred limited partners' interest in net income	(9)	—	(18)	—
Series B preferred limited partners' interest in net income	(2)	—	(2)	—
General partner’s interest in net income	(40)	(41)	(81)	(83)
Net income allocable to limited partners	$10	$47	$22	$106
Net income per limited partner unit — basic and diluted	$0.07	$0.33	$0.15	$0.74
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
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(millions)			
Net income	$62	$89	$125	$190
Other comprehensive income:				
Reclassification of cash flow hedge losses into earnings	1	—	1	1
Total other comprehensive income	1	—	1	1
Total comprehensive income	63	89	126	191
Total comprehensive income attributable to noncontrolling interests	(1)	(1)	(2)	(1)
Total comprehensive income attributable to partners	$62	$88	$124	$190

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30,	
	2018	2017
	(millions)	
OPERATING ACTIVITIES:		
Net income	$125	$190
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	191	188
Earnings from unconsolidated affiliates	(174)	(160)
Distributions from unconsolidated affiliates	193	177
Net unrealized losses (gains) on derivative instruments	66	(60)
Gain on sale of assets, net	—	(34)
Other, net	9	21
Change in operating assets and liabilities, which provided (used) cash, net of effects of acquisitions:		
Accounts receivable	(50)	98
Inventories	21	21
Accounts payable	42	(137)
Other assets and liabilities	(92)	56
Net cash provided by operating activities	331	360
INVESTING ACTIVITIES:		
Capital expenditures	(268)	(159)
Investments in unconsolidated affiliates, net	(126)	(41)
Proceeds from sale of assets	3	129
Net cash used in investing activities	(391)	(71)
FINANCING ACTIVITIES:		
Proceeds from long-term debt	1,803	—
Payments of long-term debt	(1,678)	(195)
Proceeds from issuance of preferred limited partner units, net of offering costs	155	—
Distributions to preferred limited partners	(21)	—
Net change in advances to predecessor from DCP Midstream, LLC	—	418
Distributions to limited partners and general partner	(349)	(256)
Distributions to noncontrolling interests	(2)	(4)
Other	—	(2)
Net cash used in financing activities	(92)	(39)
Net change in cash and cash equivalents	(152)	250
Cash and cash equivalents, beginning of period	156	1
Cash and cash equivalents, end of period	$4	$251

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	18	2	22	81	—	2	125
Other comprehensive income	—	—	—	—	1	—	1
Issuance of 6,450,000 Series B Preferred Units	—	155	—	—	—	—	155
Distributions to unitholders	(21)	—	(223)	(126)	—	—	(370)
Distributions to noncontrolling interests	—	—	—	—	—	(2)	(2)
Balance, June 30, 2018	$ 488	$ 157	$6,577	$ 109	$ (8)	$ 30	$7,353

See accompanying notes to condensed consolidated financial statements.

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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	—	106	83	—	1	190
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	—	(202)	(54)	—	—	(256)
Distributions to noncontrolling interests	—	—	—	—	(4)	(4)
Balance, June 30, 2017	$—	$7,040	$ 139	$ (9)	$ 29	$7,199

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017
(Unaudited)

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 15 - 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 June 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. 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 six months ended June 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..

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

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 are currently evaluating the potential impact this standard will have on our condensed consolidated financial statements and related disclosures.

FASB ASU 2014-09 “Revenue from Contracts with Customers (Topic 606),” or ASU 2014-09 and related interpretations and amendments - In May 2014, the FASB issued ASU 2014-09, which supersedes the revenue recognition requirements of Accounting Standards Codification Topic 605 “Revenue Recognition.” 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 June 30, 2018			Six Months Ended June 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	$1,849	$ 44	$ 1,893	$3,593	$ 75	$ 3,668
Transportation, processing and other	$127	$ 39	$ 166	$238	$ 79	$ 317
Costs and expenses						
Purchases and related costs	$1,703	$ 83	$ 1,786	$3,307	$ 154	$ 3,461
Net income	$62	$ —	$ 62	$125	$ —	$ 125

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 June 30, 2018			
	Gathering and Processing	Logistics and Marketing	Eliminations	Total
	(millions)			
Sales of natural gas	$398	$ 463	$ (353)	$508
Sales of NGLs and condensate (a)	870	1,714	(835)	1,749
Transportation, processing and other	112	16	(1)	127
Trading and marketing losses, net (c)	(66)	(1)	—	(67)
Total operating revenues	$1,314	$ 2,192	$ (1,189)	$2,317

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

	Six Months Ended June 30, 2018			
	Gathering and Processing	Logistics and Marketing	Eliminations	Total
	(millions)			
Sales of natural gas	$844	$ 1,016	$ (772)	$1,088
Sales of NGLs and condensate (b)	1,610	3,170	(1,542)	3,238
Transportation, processing and other	209	30	(1)	238
Trading and marketing losses, net (c)	(63)	(45)	—	(108)
Total operating revenues	$2,600	$ 4,171	$ (2,315)	$4,456

(a) Includes $1,108 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 $1,901 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 balance sheet:

	June 30, 2018
	(millions)
Balance, beginning of period	$ —
Cumulative effect of implementation of Topic 606	36
Revenue recognized (a)	(1)
Balance, end of period	$ 35
Current contract liabilities	—
Long-term contract liabilities	$ 35

(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 June 30, 2018.

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DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(millions)			
Employee related costs charged by DCP Midstream, LLC				
Operating and maintenance expense	$53	$ 49	$102	$ 99
General and administrative expense	$47	$ 39	$85	$ 70

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 June 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.

DCP MIDSTREAM, LP
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Summary of Transactions with Affiliates

The following table summarizes our transactions with affiliates:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(millions)			
Phillips 66 (including its affiliates):				
Sales of natural gas, NGLs and condensate to affiliates	$381	$251	$683	$525
Purchases and related costs from affiliates	$28	$8	$38	$15
Operating and maintenance and general administrative expenses	$3	$—	$6	$1
Enbridge (including its affiliates):				
Sales of natural gas, NGLs and condensate to affiliates	$13	$15	$25	$20
Purchases and related costs from affiliates	$18	$11	$28	$19
Operating and maintenance and general administrative expenses	$—	$—	$—	$1
Unconsolidated affiliates:				
Sales of natural gas, NGLs and condensate to affiliates	$14	$12	$25	$22
Transportation, processing, and other to affiliates	$2	$2	$3	$3
Purchases and related costs from affiliates	$179	$119	$324	$232

We had balances with affiliates as follows:

	June 30, 2018	December 31, 2017
	(millions)	
Phillips 66 (including its affiliates):		
Accounts receivable	$153	$ 156
Accounts payable	$24	$ 6
Other assets	$1	$ —
Enbridge (including its affiliates):		
Accounts receivable	$14	$ 11
Accounts payable	$21	$ 9
Unconsolidated affiliates:		
Accounts receivable	$22	$ 24
Accounts payable	$67	$ 53
Other assets	$3	$ 4

6. Inventories

Inventories were as follows:

	June 30, 2018	December 31, 2017
	(millions)	
Natural gas	$18	$ 30
NGLs	29	38
Total inventories	$47	$ 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 six months ended June 30, 2018 and June 30, 2017, respectively.

7. Property, Plant and Equipment

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

	Depreciable Life	June 30, 2018	December 31, 2017
		(millions)	
Gathering and transmission systems	20 — 50 Years	$8,599	$ 8,473
Processing, storage and terminal facilities	35 — 60 Years	5,141	5,128
Other	3 — 30 Years	563	557
Construction work in progress		520	374
Property, plant and equipment		14,823	14,532
Accumulated depreciation		(5,743)	(5,549)
Property, plant and equipment, net		$9,080	$ 8,983

Interest capitalized on construction projects was $6 million and $1 million for the three months ended June 30, 2018 and 2017, respectively, and $11 million and $2 million for the six months ended June 30, 2018 and 2017, respectively. Depreciation expense was $94 million and $90 million for the three months ended June 30, 2018 and 2017, respectively, and $186 million and $182 million for the six months ended June 30, 2018 and 2017, respectively.

DCP MIDSTREAM, LP
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8. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage Ownership	Carrying Value as of June 30, 2018	Carrying Value as of December 31, 2017
		(millions)	
DCP Sand Hills Pipeline, LLC	66.67%	$1,730	$ 1,633
DCP Southern Hills Pipeline, LLC	66.67%	735	739
Discovery Producer Services LLC	40.00%	354	362
Front Range Pipeline LLC	33.33%	163	165
Texas Express Pipeline LLC	10.00%	91	90
Gulf Coast Express Pipeline LLC	25.00%	28	—
Mont Belvieu Enterprise Fractionator	12.50%	25	23
Panola Pipeline Company, LLC	15.00%	23	24
Mont Belvieu 1 Fractionator	20.00%	12	10
Other	Various	4	4
Total investments in unconsolidated affiliates		$3,165	$ 3,050

Earnings from investments in unconsolidated affiliates were as follows:

	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
	(millions)			
DCP Sand Hills Pipeline, LLC	$58	$ 37	$106	$68
DCP Southern Hills Pipeline, LLC	16	13	29	24
Discovery Producer Services LLC	2	25	3	45
Front Range Pipeline LLC	5	3	10	7
Texas Express Pipeline LLC	8	1	10	3
Mont Belvieu Enterprise Fractionator	3	4	7	7
Mont Belvieu 1 Fractionator	4	3	8	4
Other	—	—	1	2
Total earnings from unconsolidated affiliates	$96	$ 86	$174	$160

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(millions)			
Statements of operations: (a)				
Operating revenue	$408	$368	$742	$705
Operating expenses	$147	$152	$286	$300
Net income	$260	$216	$454	$404

	June 30, 2018	December 31, 2017
	(millions)	
Balance sheets: (a)		
Current assets	$379	$ 244
Long-term assets	5,596	5,319
Current liabilities	(256)	(196)
Long-term liabilities	(227)	(200)
Net assets	$5,492	$ 5,167

(a) In accordance with the Gulf Coast Express Pipeline LLC ("GCX") joint venture agreement, earnings do not accrue to our interest until the construction of the pipeline is complete. Accordingly, we will not include activity related to GCX in the above tables until the period in which the construction is complete and earnings accrue to our interest.

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9. 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 11 - Risk Management and Hedging Activities.

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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.

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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.

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

	June 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)	$36	$ 8	$ 1	$ 45	$10	$ 17	$ 3	$ 30
Short-term investments (b)	$3	$ —	$ —	$ 3	$156	$ —	$ —	$ 156
Long-term assets:								
Commodity derivatives (c)	$6	$ 1	$ 1	$ 8	$1	$ 1	$ 1	$ 3
Current liabilities:								
Commodity derivatives (d)	$(77)	$ (54)	$ (10)	$ (141)	$(29)	$ (34)	$ (13)	$ (76)
Long-term liabilities:								
Commodity derivatives (e)	$(12)	$ (10)	$ (7)	$ (29)	$(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.

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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 six months ended June 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 June 30, 2018 (a):				
Beginning balance	$2	$ —	$ (6)	$ (3)
Net unrealized gains (losses) included in earnings (b)	1	1	(14)	(4)
Transfers out of Level 3 (c)	(2)	—	8	—
Settlements	—	—	2	—
Ending balance	$1	$ 1	$ (10)	$ (7)
Net unrealized gains (losses) on derivatives still held included in earnings (b)	$1	$ 1	$ (8)	$ (4)
Three months ended June 30, 2017 (a):				
Beginning balance	$8	$ 2	$ (8)	$ (3)
Net unrealized gains included in earnings (b)	3	—	1	—
Transfers out of Level 3 (c)	(3)	—	3	—
Settlements	(1)	—	2	—
Ending balance	$7	$ 2	$ (2)	$ (3)
Net unrealized gains on derivatives still held included in earnings (b)	$4	$ —	$ —	$ —

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	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(millions)			
Six months ended June 30, 2018 (a):				
Beginning balance	$3	$ 1	$ (13)	$ (1)
Net unrealized losses included in earnings (b)	—	—	(12)	(6)
Transfers out of Level 3 (c)	(2)	—	12	—
Settlements	—	—	3	—
Ending balance	$1	$ 1	$ (10)	$ (7)
Net unrealized gains (losses) on derivatives still held included in earnings (b)	$1	$ —	$ (7)	$ (6)
Six months ended June 30, 2017 (a):				
Beginning balance	$9	$ 5	$ (23)	$ —
Net unrealized gains (losses) included in earnings (b)	1	(3)	13	(3)
Transfers out of Level 3 (c)	(2)	—	3	—
Settlements	(1)	—	5	—
Ending balance	$7	$ 2	$ (2)	$ (3)
Net unrealized gains (losses) on derivatives still held included in earnings (b)	$6	$ (2)	$ 3	$ (3)

(a) There were no purchases, issuances or sales of derivatives or transfers into Level 3 for the three and six months ended June 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.

	June 30, 2018		
Product Group	Fair Value	Forward Curve Range	
	(millions)		
Assets			
NGLs	$2	$0.29-$1.08	Per gallon
Liabilities			
NGLs	$(12)	$0.14-$1.49	Per gallon
Natural gas	$(5)	$1.57-$2.66	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.

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

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

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

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

We determine the fair value of our fixed-rate senior notes and junior subordinated notes based on quotes obtained from bond dealers. We determine the fair value of borrowings under our Credit Agreement based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. We classify the fair values of our outstanding debt balances within Level 2 of the valuation hierarchy. As of June 30, 2018 and December 31, 2017, the carrying value and fair value of our total debt, including current maturities, were as follows:

	June 30, 2018		December 31, 2017	
	Carrying Value (a)	Fair Value	Carrying Value (a)	Fair Value
	(millions)			
Total debt	$4,861	$4,896	$4,736	$4,885

(a) Excludes unamortized issuance costs.

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10. Debt

	June 30, 2018	December 31, 2017
	(millions)	
Senior notes:		
Issued February 2009, interest at 9.750% payable semiannually, due March 2019 (a)	$450	$ 450
Issued March 2014, interest at 2.700% payable semi-annually, due April 2019	325	325
Issued March 2010, interest at 5.350% payable semiannually, due March 2020 (a)	600	600
Issued September 2011, interest at 4.750% payable semiannually, due September 2021	500	500
Issued March 2012, interest at 4.950% payable semi-annually, due April 2022	350	350
Issued March 2013, interest at 3.875% payable semi-annually, due March 2023	500	500
Issued August 2000, interest at 8.125% payable semi-annually, due August 2030 (a)	300	300
Issued October 2006, interest at 6.450% payable semi-annually, due November 2036	300	300
Issued September 2007, interest at 6.750% payable semi-annually, due September 2037	450	450
Issued March 2014, interest at 5.600% payable semi-annually, due April 2044	400	400
Junior subordinated notes:		
Issued May 2013, interest at 5.850% payable semi-annually, due May 2043	550	550
Credit agreement:		
Revolving credit facility, weighted-average variable interest rate of 3.452%, as of June 30, 2018, due December 2022	125	—
Fair value adjustments related to interest rate swap fair value hedges (a)	22	23
Unamortized issuance costs	(26)	(29)
Unamortized discount	(11)	(12)
Total debt	4,835	4,707
Current maturities of long-term debt	325	—
Total long-term debt	$4,510	$ 4,707

(a) The swaps associated with this debt were previously terminated. The remaining long-term fair value of approximately
$22 million related to the swaps is being amortized as a reduction to interest expense through 2019, 2020 and 2030, the original maturity dates of the debt.

Credit Agreement
We are a party to a $1.4 billion unsecured revolving 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: (a) 5.25 to 1.0 for the fiscal quarter ending June 30, 2018, and (b) 5.00 to 1.0 for each fiscal quarter ending thereafter; provided that, if there is a Qualified Acquisition (as defined in the Credit Agreement) during any fiscal quarter ending June 30, 2018 or thereafter, the maximum Consolidated Leverage Ratio shall not exceed 5.50 to 1.0 at the end of the three consecutive fiscal quarters, including the fiscal quarter in which the

Qualified Acquisition occurs.

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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 June 30, 2018, we had unused borrowing capacity of $1,250 million, net of $25 million of letters of credit, under the Credit Agreement. Our borrowing capacity may be limited by financial covenants set forth in the Credit Agreement. The financial covenants set forth in the Credit Agreement limit the Partnership's ability to incur incremental debt by the unused borrowing capacity of $1,250 million as of June 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 long-term debt as of June 30, 2018 are as follows:

	Debt Maturities (millions)
2018	$ —
2019	775
2020	600
2021	500
2022	475
Thereafter	2,500
Total long-term debt	$ 4,850

11. 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 June 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. 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.

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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 June 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 June 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 June 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

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with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of June 30, 2018, we have not been required to post additional collateral.

Collateral

As of June 30, 2018, we had cash deposits of $138 million, included in collateral cash deposits in our condensed consolidated balance sheets, and letters of credit of $13 million with counterparties to secure our obligations to provide future services or to perform under financial contracts. Additionally, as of June 30, 2018, we held cash of $6 million, included in other current liabilities in our condensed consolidated balance sheet, related to cash postings by third parties and letters of credit of $43 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:

	June 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	$53	$ —	$53	$33	$ —	$ 33
Liabilities:						
Commodity derivatives	$(170)	$ —	$(170)	$(91)	$ —	$ (91)

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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 June 30, 2018 and December 31, 2017.

Balance Sheet Line Item	June 30, 2018	December 31, 2017	Balance Sheet Line Item	June 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	$ 45	$ 30	Unrealized losses on derivative instruments — current	$ (141)	$ (76)
Unrealized gains on derivative instruments — long-term	8	3	Unrealized losses on derivative instruments — long-term	(29)	(15)
Total	$ 53	$ 33	Total	$ (170)	$ (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 June 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	$ (1)	$ —	$ —	$ (1)

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 six months ended June 30, 2018:

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

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The following summarizes the balance and activity within AOCI relative to our interest rate, commodity and foreign currency cash flow hedges as of and for the three months ended June 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 six months ended June 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 six months ended June 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 six months ended June 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(millions)			
Realized losses	$(30)	$(2)	$(42)	$(7)
Unrealized (losses) gains	(37)	24	(66)	60
Trading and marketing (losses) gains, net	$(67)	$22	$(108)	$53

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.

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	June 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 Long Position (MMBtu)
2018	(1,646,000)	(21,623,200)	(25,737,691)	2,257,500
2019	(1,900,000)	—	(19,314,335)	1,512,500
2020	(128,000)	—	(13,568,452)	3,660,000
2021	—	—	(5,750,000)	—

	June 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	(282,000)	(29,043,200)	(15,547,868)	2,075,000
2018	(772,000)	(17,855,000)	(2,262,338)	2,350,000
2019	(150,000)	—	292,700	2,025,000
2020	(50,000)	—	238,548	—

12. Partnership Equity and Distributions

Preferred Units — On May 11, 2018, we issued 6,000,000 of our Series B Preferred Units representing limited partnership interests at a price of $25 per unit. On June 4, 2018, we issued an additional 450,000 Series B Preferred Units which represented the partial exercise of the underwriters' option to purchase additional Series B Preferred Units. We used the net proceeds of $155 million from the issuance of the Series B Preferred Units for general partnership purposes including funding capital expenditures and the repayment of outstanding indebtedness under our revolving credit facility.

Distributions of the Series B Preferred Units are payable out of available cash, accrue and are cumulative from the date of original issuance of the Series B Preferred Units and are payable quarterly in arrears on March 15th, June 15th, September 15th and December 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 7.875% per year of the $25 liquidation preference per unit (equal to $1.9688 per unit). On and after June 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 4.919%. The Series B Preferred Units rank senior to our common units with respect to distribution rights and rights upon liquidation.

At any time prior to June 15, 2023, within 120 days of a ratings event, we may, at our option, redeem the Series B Preferred Units in whole, but not in part, at a redemption price per unit equal to $25.50 (102% of the liquidation preference), plus an amount equal to all accumulated and unpaid distributions. At any time on or after June 15, 2023, we may redeem, in whole or in part, the units at a redemption price of $25 per unit, plus an amount equal to all accumulated and unpaid distributions. Upon occurrence of a change in control triggering event, we may, at our option, (i) redeem the Series B Preferred Units, in whole or in part, within 120 days, by paying $25 per unit, plus all accumulated and unpaid distributions, and (ii) each holder of Series B Preferred Units will have the right (unless the Partnership provided notice of its election to redeem such holder's Series B Preferred Units) to convert some or all of the Series B Preferred Units held by such holder on the change of control conversion date into a number of the Partnership's common units per Series B Preferred Unit as defined in our Partnership Agreement. Holders of the Series B Preferred Units have no voting rights except for certain limited protective voting rights set forth in our Partnership Agreement.

Common Units — During the six months ended June 30, 2018 and 2017, we issued no common units pursuant to our 2014 equity distribution agreement. As of June 30, 2018, approximately $750 million of common units remained available for sale pursuant to our at-the-market program.

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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		
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
Distributions to Series A Preferred unitholders		
June 15, 2018	$ 41.9965	$ 21

13. 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. Potential dilutive units include outstanding awards under the Partnership's Long Term Incentive Plans.

14. 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.

On May 24, 2018, we agreed to an administrative civil penalty of approximately $100,700 with the New Mexico Environment Department to resolve claims in a notice of violation issued on July 14, 2017 in connection with malfunction-related excess emissions at one our gas processing plants occurring between January and April 2017 that we recorded and reported to the agency.

15. 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.

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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 June 30, 2018

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
	(millions)				
Total operating revenue	$1,314	$ 2,192	$—	$ (1,189)	$2,317
Gross margin (a)	$333	$ 56	$—	$ —	$389
Operating and maintenance expense	(169)	(11)	(5)	—	(185)
Depreciation and amortization expense	(87)	(3)	(7)	—	(97)
General and administrative expense	(2)	(3)	(65)	—	(70)
Other expense	—	(3)	—	—	(3)
Earnings from unconsolidated affiliates	2	94	—	—	96
Interest expense	—	—	(67)	—	(67)
Income tax expense	—	—	(1)	—	(1)
Net income (loss)	$77	$ 130	$(145)	$ —	$62
Net income attributable to noncontrolling interests	(1)	—	—	—	(1)
Net income (loss) attributable to partners	$76	$ 130	$(145)	$ —	$61
Non-cash derivative mark-to-market (b)	$(42)	$ 5	$—	$ —	$(37)
Capital expenditures	$140	$ —	$4	$ —	$144
Investments in unconsolidated affiliates, net	$—	$ 66	$—	$ —	$66

Three Months Ended June 30, 2017:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
	(millions)				
Total operating revenue	$1,269	$ 1,756	$—	$ (1,076)	$1,949
Gross margin (a)	$342	$ 50	$—	$ —	$392
Operating and maintenance expense	(162)	(13)	(3)	—	(178)
Depreciation and amortization expense	(86)	(3)	(5)	—	(94)
General and administrative expense	(7)	(2)	(62)	—	(71)
Other expense	(3)	(2)	—	—	(5)
Gain on sale of assets, net	34	—	—	—	34
Earnings from unconsolidated affiliates	24	62	—	—	86
Interest expense	—	—	(73)	—	(73)
Income tax expense	—	—	(2)	—	(2)
Net income (loss)	$142	$ 92	$(145)	$ —	$89
Net income attributable to noncontrolling interests	(1)	—	—	—	(1)

Net income (loss) attributable to partners	$141	$ 92	$(145)	$ —	$88
Non-cash derivative mark-to-market (b)	$16	$ 8	$—	$ —	$24
Capital expenditures	$103	$ —	$8	$ —	$111
Investments in unconsolidated affiliates, net	$—	$ 21	$—	$ —	$21

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

Six Months Ended June 30, 2018:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
	(millions)				
Total operating revenue	$2,600	$ 4,171	$—	$ (2,315)	$4,456
Gross margin (a)	$685	$ 74	$—	$ —	$759
Operating and maintenance expense	(317)	(22)	(8)	—	(347)
Depreciation and amortization expense	(171)	(6)	(14)	—	(191)
General and administrative expense	(6)	(6)	(117)	—	(129)
Other expense, net	(3)	(2)	—	—	(5)
Earnings from unconsolidated affiliates	3	171	—	—	174
Interest expense	—	—	(134)	—	(134)
Income tax expense	—	—	(2)	—	(2)
Net income (loss)	$191	$ 209	$(275)	$ —	$125
Net income attributable to noncontrolling interests	(2)	—	—	—	(2)
Net income (loss) attributable to partners	$189	$ 209	$(275)	$ —	$123
Non-cash derivative mark-to-market (b)	$(28)	$ (38)	$—	$ —	$(66)
Capital expenditures	$260	$ 1	$7	$ —	$268
Investments in unconsolidated affiliates, net	$1	$ 125	$—	$ —	$126

Six Months Ended June 30, 2017:

	Gathering and Processing	Logistics and Marketing	Other	Eliminations	Total
	(millions)				
Total operating revenue	$2,628	$ 3,683	$—	$ (2,241)	$4,070
Gross margin (a)	$718	$ 108	$—	$ —	$826
Operating and maintenance expense	(315)	(22)	(8)	—	(345)
Depreciation and amortization expense	(171)	(7)	(10)	—	(188)
General and administrative expense	(13)	(5)	(115)	—	(133)
Other expense	(3)	(11)	(1)	—	(15)
Gain on sale of assets, net	34	—	—	—	34
Earnings from unconsolidated affiliates	44	116	—	—	160
Interest expense	—	—	(146)	—	(146)
Income tax expense	—	—	(3)	—	(3)
Net income (loss)	$294	$ 179	$(283)	$ —	$190
Net income attributable to noncontrolling interests	(1)	—	—	—	(1)
Net income (loss) attributable to partners	$293	$ 179	$(283)	$ —	$189
Non-cash derivative mark-to-market (b)	$47	$ 13	$—	$ —	$60
Capital expenditures	$146	$ 1	$12	$ —	$159
Investments in unconsolidated affiliates, net	$—	$ 41	$—	$ —	$41

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

	June 30, 2018	December 31, 2017
	(millions)	
Segment long-term assets:		
Gathering and Processing	$9,048	$ 8,943
Logistics and Marketing	3,462	3,348
Other (c)	249	265
Total long-term assets	12,759	12,556
Current assets	1,282	1,322
Total assets	$14,041	$ 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.

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

16. Supplemental Cash Flow Information

	Six Months Ended June 30,	
	2018	2017
	(millions)	
Cash paid for interest:		
Cash paid for interest, net of amounts capitalized	$129	$143
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	$42	$33
Other non-cash changes in property, plant and equipment	$—	$(2)
Issuance of common and general partner units	$—	$1,125
Deficit purchase price	$—	$3,094

17. 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.

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

Condensed Consolidating Balance Sheet
June 30, 2018

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(millions)				
ASSETS					
Current assets:					
Cash and cash equivalents	$—	$ —	$ 4	$ —	$ 4
Accounts receivable, net	—	—	1,029	—	1,029
Inventories	—	—	47	—	47
Other	—	—	202	—	202
Total current assets	—	—	1,282	—	1,282
Property, plant and equipment, net	—	—	9,080	—	9,080
Goodwill and intangible assets, net	—	—	332	—	332
Advances receivable — consolidated subsidiaries	2,680	1,763	—	(4,443)	—
Investments in consolidated subsidiaries	4,643	7,785	—	(12,428)	—
Investments in unconsolidated affiliates	—	—	3,165	—	3,165
Other long-term assets	—	—	182	—	182
Total assets	$7,323	$ 9,548	$ 14,041	$ (16,871)	$ 14,041
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$—	$ 70	$ 1,492	$ —	$ 1,562
Current maturities of long-term debt	—	325	—	—	325
Advances payable — consolidated subsidiaries	—	—	4,443	(4,443)	—
Long-term debt	—	4,510	—	—	4,510
Other long-term liabilities	—	—	291	—	291
Total liabilities	—	4,905	6,226	(4,443)	6,688
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Net equity	7,323	4,646	7,790	(12,428)	7,331
Accumulated other comprehensive loss	—	(3)	(5)	—	(8)
Total partners' equity	7,323	4,643	7,785	(12,428)	7,323
Noncontrolling interests	—	—	30	—	30
Total equity	7,323	4,643	7,815	(12,428)	7,353
Total liabilities and equity	$7,323	$ 9,548	$ 14,041	$ (16,871)	$ 14,041

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

Condensed Consolidating Balance Sheet
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

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

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

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(millions)				
Operating revenues:					
Sales of natural gas, NGLs and condensate	$—	$ —	$ 2,257	$ —	$ 2,257
Transportation, processing and other	—	—	127	—	127
Trading and marketing losses, net	—	—	(67)	—	(67)
Total operating revenues	—	—	2,317	—	2,317
Operating costs and expenses:					
Purchases and related costs	—	—	1,928	—	1,928
Operating and maintenance expense	—	—	185	—	185
Depreciation and amortization expense	—	—	97	—	97
General and administrative expense	—	—	70	—	70
Other expense, net	—	—	3	—	3
Total operating costs and expenses	—	—	2,283	—	2,283
Operating income	—	—	34	—	34
Interest expense, net	—	(67)	—	—	(67)
Income from consolidated subsidiaries	61	128	—	(189)	—
Earnings from unconsolidated affiliates	—	—	96	—	96
Income before income taxes	61	61	130	(189)	63
Income tax expense	—	—	(1)	—	(1)
Net income	61	61	129	(189)	62
Net income attributable to noncontrolling interests	—	—	(1)	—	(1)
Net income attributable to partners	$61	$ 61	$ 128	$ (189)	$ 61

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

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(millions)				
Net income	$61	$ 61	$ 129	$ (189)	$ 62
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	62	62	129	(190)	63
Total comprehensive income attributable to noncontrolling interests	—	—	(1)	—	(1)
Total comprehensive income attributable to partners	$62	$ 62	$ 128	$ (190)	$ 62

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

	Condensed Consolidating Statement of Operations Three Months Ended June 30, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(millions)				
Operating revenues:					
Sales of natural gas, NGLs and condensate	$—	$ —	$ 1,772	$ —	$ 1,772
Transportation, processing and other	—	—	155	—	155
Trading and marketing gains, net	—	—	22	—	22
Total operating revenues	—	—	1,949	—	1,949
Operating costs and expenses:					
Purchases of natural gas and NGLs	—	—	1,557	—	1,557
Operating and maintenance expense	—	—	178	—	178
Depreciation and amortization expense	—	—	94	—	94
General and administrative expense	—	—	71	—	71
Gain on sale of assets, net	—	—	(34)	—	(34)
Other expense, net	—	—	5	—	5
Total operating costs and expenses	—	—	1,871	—	1,871
Operating income	—	—	78	—	78
Interest expense, net	—	(73)	—	—	(73)
Income from consolidated subsidiaries	88	161	—	(249)	—
Earnings from unconsolidated affiliates	—	—	86	—	86
Income before income taxes	88	88	164	(249)	91
Income tax expense	—	—	(2)	—	(2)
Net income	88	88	162	(249)	89
Net income attributable to noncontrolling interests	—	—	(1)	—	(1)
Net income attributable to partners	$88	$ 88	$ 161	$ (249)	$ 88

	Condensed Consolidating Statement of Comprehensive Income Three Months Ended June 30, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(millions)				
Net income	$88	$ 88	$ 162	$ (249)	$ 89
Total other comprehensive income	—	—	—	—	—
Total comprehensive income	88	88	162	(249)	89
Total comprehensive income attributable to noncontrolling interests	—	—	(1)	—	(1)
Total comprehensive income attributable to partners	$88	$ 88	$ 161	$ (249)	$ 88

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

Condensed Consolidating Statement of Operations
Six Months Ended June 30, 2018

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(millions)				
Operating revenues:					
Sales of natural gas, NGLs and condensate	$—	$ —	$ 4,326	$ —	$ 4,326
Transportation, processing and other	—	—	238	—	238
Trading and marketing losses, net	—	—	(108)	—	(108)
Total operating revenues	—	—	4,456	—	4,456
Operating costs and expenses:					
Purchases and related costs	—	—	3,697	—	3,697
Operating and maintenance expense	—	—	347	—	347
Depreciation and amortization expense	—	—	191	—	191
General and administrative expense	—	—	129	—	129
Other expense, net	—	—	5	—	5
Total operating costs and expenses	—	—	4,369	—	4,369
Operating income	—	—	87	—	87
Interest expense, net	—	(134)	—	—	(134)
Income from consolidated subsidiaries	123	257	—	(380)	—
Earnings from unconsolidated affiliates	—	—	174	—	174
Income before income taxes	123	123	261	(380)	127
Income tax expense	—	—	(2)	—	(2)
Net income	123	123	259	(380)	125
Net income attributable to noncontrolling interests	—	—	(2)	—	(2)
Net income attributable to partners	$123	$ 123	$ 257	$ (380)	$ 123

Condensed Consolidating Statement of Comprehensive Income
Six Months Ended June 30, 2018

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(millions)				
Net income	$123	$ 123	$ 259	$ (380)	$ 125
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	124	124	259	(381)	126
Total comprehensive income attributable to noncontrolling interests	—	—	(2)	—	(2)
Total comprehensive income attributable to partners	$124	$ 124	$ 257	$ (381)	$ 124

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

Condensed Consolidating Statement of Operations
Six Months Ended June 30, 2017

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(millions)				
Operating revenues:					
Sales of natural gas, NGLs and condensate	$—	$ —	$ 3,705	$ —	$ 3,705
Transportation, processing and other	—	—	312	—	312
Trading and marketing losses, net	—	—	53	—	53
Total operating revenues	—	—	4,070	—	4,070
Operating costs and expenses:					
Purchases and related costs	—	—	3,244	—	3,244
Operating and maintenance expense	—	—	345	—	345
Depreciation and amortization expense	—	—	188	—	188
General and administrative expense	—	—	133	—	133
Gain on sale of assets, net	—	—	(34)	—	(34)
Other expense, net	—	—	15	—	15
Total operating costs and expenses	—	—	3,891	—	3,891
Operating income	—	—	179	—	179
Interest expense, net	—	(146)	—	—	(146)
Income from consolidated subsidiaries	189	335	—	(524)	—
Earnings from unconsolidated affiliates	—	—	160	—	160
Income before income taxes	189	189	339	(524)	193
Income tax expense	—	—	(3)	—	(3)
Net income	189	189	336	(524)	190
Net income attributable to noncontrolling interests	—	—	(1)	—	(1)
Net income attributable to partners	$189	$ 189	$ 335	$ (524)	$ 189

Condensed Consolidating Statement of Comprehensive Income
Six Months Ended June 30, 2017

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(millions)				
Net income	$189	$ 189	$ 336	$ (524)	$ 190
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	190	190	336	(525)	191
Total comprehensive income attributable to noncontrolling interests	—	—	(1)	—	(1)
Total comprehensive income attributable to partners	$190	$ 190	$ 335	$ (525)	$ 190

DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

	Condensed Consolidating Statement of Cash Flows Six Months Ended June 30, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(millions)				
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (131)	$ 462	$ —	$ 331
INVESTING ACTIVITIES:					
Intercompany transfers	215	(149)	—	(66)	—
Capital expenditures	—	—	(268)	—	(268)
Investments in unconsolidated affiliates, net	—	—	(126)	—	(126)
Proceeds from sale of assets	—	—	3	—	3
Net cash provided by (used in) investing activities	215	(149)	(391)	(66)	(391)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	(66)	66	—
Proceeds from long-term debt	—	1,803	—	—	1,803
Payments of long-term debt	—	(1,678)	—	—	(1,678)
Proceeds from issuance of preferred limited partner units, net of offering costs	155	—	—	—	155
Distributions to preferred limited partners	(21)	—	—	—	(21)
Distributions to limited partners and general partner	(349)	—	—	—	(349)
Distributions to noncontrolling interests	—	—	(2)	—	(2)
Net cash (used in) provided by financing activities	(215)	125	(68)	66	(92)
Net change in cash and cash equivalents	—	(155)	3	—	(152)
Cash and cash equivalents, beginning of period	—	155	1	—	156
Cash and cash equivalents, end of period	$ —	$ —	$ 4	$ —	$ 4

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DCP MIDSTREAM, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
Three and Six Months Ended June 30, 2018 and 2017 - (Continued)
(Unaudited)

Condensed Consolidating Statements of Cash Flows
Six Months Ended June 30, 2017

	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(millions)				
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ —	$ (143)	$ 503	$ —	$ 360
INVESTING ACTIVITIES:					
Intercompany transfers	256	590	—	(846)	—
Capital expenditures	—	—	(159)	—	(159)
Investments in unconsolidated affiliates, net	—	—	(41)	—	(41)
Proceeds from sale of assets	—	—	129	—	129
Net cash provided by (used in) investing activities	256	590	(71)	(846)	(71)
FINANCING ACTIVITIES:					
Intercompany transfers	—	—	(846)	846	—
Payments of long-term debt	—	(195)	—	—	(195)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	418	—	418
Distributions to limited partners and general partner	(256)	—	—	—	(256)
Distributions to noncontrolling interests	—	—	(4)	—	(4)
Other	—	(2)	—	—	(2)
Net cash (used in) provided by financing activities	(256)	(197)	(432)	846	(39)
Net change in cash and cash equivalents	—	250	—	—	250
Cash and cash equivalents, beginning of period	—	—	1	—	1
Cash and cash equivalents, end of period	$ —	$ 250	$ 1	$ —	$ 251

18. Subsequent Events

On July 24, 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 August 14, 2018 to unitholders of record on August 3, 2018.

On the same date, we announced that the board of directors of the General Partner declared a quarterly distribution on our Series B Preferred Units of $0.6781 per Series B Preferred Unit, which includes the distribution attributable to the partial-period from and including the original issue date of May 11, 2018. The distribution will be paid on September 17, 2018 to unitholders of record on September 4, 2018.

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 expect to use 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.

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

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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.

Our Logistics and marketing segment is primarily driven by the level of production 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 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 this 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.

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.

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 in the second quarter of 2018 to 425 MBbls/d, with expansion to 485 MBbls/d expected by the end of 2018.
- 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 own 33% of Front Range and 10% of Texas Express.
- We are jointly developing the Cheyenne Connector pipeline (“Cheyenne Connector”) with Tallgrass Energy Partners, LP (operator), and Western Gas Partners, LP and hold a 33% ownership option. Cheyenne Connector will provide gas takeaway for the DJ Basin. It 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 have a 25% interest in 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 to be in-service in the fourth quarter of 2019.
- We committed to supply agreements for NGL feedstock to two 150 MBbls/d fractionators to be constructed within Phillips 66's Sweeny Hub. Additionally, we hold an option to acquire a 30% ownership interest in these fractionators. The option is exercisable at the in-service date of the fractionators, with a capital investment of approximately $400 million, net to DCP. The fractionators have an expected in service date 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 on August 1, 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 volumes are 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 expected to be placed in service in phases beginning in 2020.

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 $650 million and $750 million associated with approved projects. We forecast expansion spending to be at the high end of the range. 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 Annualu Report on Form 10-K for the year ended December 31, 2017.

Recent Events

On May 11, 2018, we issued 6,000,000 of our Series B Preferred Units representing limited partnership interests at a price of $25 per unit. On June 4, 2018, we issued an additional 450,000 Series B Preferred Units which represented the partial exercise of the underwriters’ option to purchase additional Series B Preferred Units. We used the net proceeds of $155 million from the issuance of the Series B Preferred Units for general partnership purposes including funding capital expenditures and the repayment of outstanding indebtedness under our revolving credit facility.

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 expect to use 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. The notes will mature on July 15, 2025.

We announced a quarterly distribution of $0.78 per common unit for the second quarter of 2018. This distribution per common unit remains unchanged from the previous quarter and the second quarter of 2017.

We announced a quarterly distribution on our Preferred Series B units of $0.6781 per Preferred Series B unit, which includes the distribution attributable to the partial-period from and including the original issue date of May 11, 2018.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our condensed consolidated results of operations for the three and six months ended June 30, 2018 and 2017. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2018 vs. 2017		Variance Six Months 2018 vs. 2017	
	2018	2017	2018	2017	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(millions, except operating data)							
Operating revenues (a):								
Gathering and Processing	$1,314	$1,269	$2,600	$2,628	$45	4 %	$(28)	(1)%
Logistics and Marketing	2,192	1,756	4,171	3,683	436	25 %	488	13 %
Inter-segment eliminations	(1,189)	(1,076)	(2,315)	(2,241)	113	11 %	74	3 %
Total operating revenues	2,317	1,949	4,456	4,070	368	19 %	386	9 %
Purchases and related costs								
Gathering and Processing	(981)	(927)	(1,915)	(1,910)	54	6 %	5	— %
Logistics and Marketing	(2,136)	(1,706)	(4,097)	(3,575)	430	25 %	522	15 %
Inter-segment eliminations	1,189	1,076	2,315	2,241	113	11 %	74	3 %
Total purchases	(1,928)	(1,557)	(3,697)	(3,244)	371	24 %	453	14 %
Operating and maintenance expense	(185)	(178)	(347)	(345)	7	4 %	2	1 %
Depreciation and amortization expense	(97)	(94)	(191)	(188)	3	3 %	3	2 %
General and administrative expense	(70)	(71)	(129)	(133)	(1)	(1)%	(4)	(3)%
Other expense, net	(3)	(5)	(5)	(15)	(2)	(40)%	(10)	(67)%
Gain on sale of assets, net	—	34	—	34	(34)	*	(34)	*
Earnings from unconsolidated affiliates (b)	96	86	174	160	10	12 %	14	9 %
Interest expense	(67)	(73)	(134)	(146)	(6)	(8)%	(12)	(8)%
Income tax expense	(1)	(2)	(2)	(3)	(1)	(50)%	(1)	(33)%
Net income attributable to noncontrolling interests	(1)	(1)	(2)	(1)	—	*	1	*
Net income attributable to partners	$61	$88	$123	$189	$(27)	(31)%	$(66)	(35)%
Other data:								
Gross margin (c):								
Gathering and Processing	$333	$342	$685	$718	$(9)	(3)%	$(33)	(5)%
Logistics and Marketing	56	50	74	108	$6	12 %	(34)	(31)%
Total gross margin	$389	$392	$759	$826	$(3)	(1)%	$(67)	(8)%
Non-cash commodity derivative mark-to-market	$(37)	$24	$(66)	$60	$(61)	*	$(126)	*
Natural gas wellhead (MMcf/d) (d)	4,797	4,483	4,632	4,532	314	7 %	100	2 %
NGL gross production (MBbls/d) (d)	426	366	405	359	60	16 %	46	13 %
NGL pipelines throughput (MBbls/d) (d)	592	451	555	439	141	31 %	116	26 %

* Percentage change is not meaningful.

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

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(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 June 30, 2018 vs. Three Months Ended June 30, 2017

Total Operating Revenues — Total operating revenues increased $368 million in 2018 compared to 2017 primarily as a result of the following:

- $436 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;
- $45 million increase for our Gathering and Processing segment due to higher NGL and crude prices, higher gas and NGL sales volumes due to growth projects primarily related to our DJ Basin system in the North region, increased drilling activity in our Eagle Ford system in the South 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, lower volumes in our Permian region due to operational factors impacting both sales and purchases, unfavorable commodity derivative activity and the implementation of ASC 606;

These increases were partially offset by:

- $113 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 $371 million in 2018 compared to 2017 primarily as a result of the following:

- $430 million increase for our Logistics and Marketing segment for the reasons discussed above, and;
- $54 million increase for our Gathering and Processing segment for the reasons discussed above;

These increases were partially offset by:

- $113 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, partially offset by the sale of our Douglas gathering system in June 2017 in our North 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 increased in 2018 compared to 2017 primarily as a result of the expansion and volume ramp up of the Sand 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. We expect the volume declines from these wells to impact future earnings.

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 decreased in 2018 compared to 2017 for the reasons discussed above.

Gross Margin — Gross margin decreased $3 million in 2018 compared to 2017 primarily as a result of the following:

- $9 million decrease for our Gathering and Processing segment primarily related to unfavorable commodity derivative activity, lower volumes in our Permian region due to operational factors and the sale of our Douglas gathering system in June 2017. These decreases were partially offset by increased volumes from 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, increased volumes and better operational performance in the Midcontinent region and higher commodity prices.

These decreases were partially offset by:

- $6 million increase for our Logistics and Marketing segment primarily related to higher gas marketing due to favorable commodity spreads, higher NGL marketing margins, improved pipeline throughput, partially offset by unfavorable commodity derivative activity.

Six Months Ended June 30, 2018 vs. Six Months Ended June 30, 2017

Total Operating Revenues — Total operating revenues increased $386 million in 2018 compared to 2017 primarily as a result of the following:

- $488 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;

These increases were partially offset by:

- $28 million decrease for our Gathering and Processing segment due to lower natural gas prices, the sale of our Douglas gathering system in June 2017, a specific producer arrangement in our North region, lower volumes in our Permian region due to weather impacting operations and operational factors impacting both sales and purchases, unfavorable commodity derivative activity and the implementation of ASC 606. These decreases were partially offset by higher NGL and crude prices, higher gas and NGL sales volumes impacting both sales and purchases due to growth projects primarily related to our DJ Basin system in the North region, increased drilling activity in our Eagle Ford system in the South region and increased volumes and better operational performance in our Midcontinent region, and;
- $74 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 $453 million in 2018 compared to 2017 primarily as a result of the following:

- $522 million increase for our Logistics and Marketing segment for the reasons discussed above.
- $5 million increase for our Gathering and Processing segment for the reasons discussed above;

These increases were partially offset by:

- $74 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;

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.

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 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. We expect the volume declines from these wells to impact future earnings.

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 decreased in 2018 compared to 2017 for the reasons discussed above.

Gross Margin — Gross margin decreased $67 million in 2018 compared to 2017 primarily as a result of the following:

- $33 million decrease for our Gathering and Processing segment primarily related to unfavorable commodity derivative activity, the sale of our Douglas gathering system in June 2017, a producer settlement in 2017 in our North region and lower volumes in our Permian region due to weather impacting operations and operational factors. These decreases were partially offset by increased volumes from 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, increased volumes and better operational performance in the Midcontinent region and higher commodity prices.
- $34 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 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(millions)			
DCP Sand Hills Pipeline, LLC	$58	$ 37	$106	$68
DCP Southern Hills Pipeline, LLC	16	13	29	24
Front Range Pipeline LLC	5	3	10	7
Texas Express Pipeline LLC	8	1	10	3
Mont Belvieu Enterprise Fractionator	3	4	7	7
Mont Belvieu 1 Fractionator	4	3	8	4
Discovery Producer Services LLC	2	25	3	45
Other	—	—	1	2
Total earnings from unconsolidated affiliates	$96	$ 86	$174	$160

Distributions received from unconsolidated affiliates were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(millions)			
DCP Sand Hills Pipeline, LLC	$62	$46	$111	$73
DCP Southern Hills Pipeline, LLC	20	19	36	31
Front Range Pipeline LLC	6	5	12	7
Texas Express Pipeline LLC	4	2	9	5
Mont Belvieu Enterprise Fractionator	3	2	6	6
Mont Belvieu 1 Fractionator	3	3	6	4
Discovery Producer Services LLC	4	24	12	49
Other	—	—	1	2
Total distributions from unconsolidated affiliates	$102	$101	$193	$177

Results of Operations — Gathering and Processing Segment

Operating Data

Regions	Plants	Approximate Gathering and Transmission Systems (Miles)	Approximate Net Nameplate Plant Capacity (MMcf/d) (a)	Three Months Ended June 30, 2018 Natural Gas Wellhead Volume (MMcf/d) (a)	Three Months Ended June 30, 2018 NGL Production (MBbls/d) (a)	Six Months Ended June 30, 2018 Natural Gas Wellhead Volume (MMcf/d) (a)	Six Months Ended June 30, 2018 NGL Production (MBbls/d) (a)
North	13	4,000	1,260	1,206	94	1,206	89
Permian	15	16,500	1,390	919	110	895	106
Midcontinent	12	29,000	1,765	1,336	115	1,265	109
South	20	7,500	3,295	1,336	107	1,266	101
Total	60	57,000	7,710	4,797	426	4,632	405

(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 June 30,		Six Months Ended June 30,		Variance Three Months 2018 vs. 2017		Variance Six 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	$1,268	$1,116	$2,454	$2,313	$152	14 %	$141	6 %
Transportation, processing and other	112	139	209	279	(27)	(19)%	(70)	(25)%
Trading and marketing (losses) gains, net	(66)	14	(63)	36	(80)	*	(99)	*
Total operating revenues	1,314	1,269	2,600	2,628	45	4 %	(28)	(1)%
Purchases and related costs	(981)	(927)	(1,915)	(1,910)	54	6 %	5	*
Operating and maintenance expense	(169)	(162)	(317)	(315)	7	4 %	2	1 %
Depreciation and amortization expense	(87)	(86)	(171)	(171)	1	1 %	—	*
General and administrative expense	(2)	(7)	(6)	(13)	(5)	(71)%	(7)	(54)%
Other expense, net	—	(3)	(3)	(3)	3	*	—	*
Gain on sale of assets, net	—	34	—	34	(34)	*	(34)	*
Earnings from unconsolidated affiliates (a)	2	24	3	44	(22)	(92)%	(41)	(93)%
Segment net income	77	142	191	294	(65)	(46)%	(103)	(35)%
Segment net income attributable to noncontrolling interests	(1)	(1)	(2)	(1)	—	*	1	*
Segment net income attributable to partners	$76	$141	$189	$293	$(65)	(46)%	$(104)	(35)%
Other data:								
Segment gross margin (b)	$333	$342	$685	$718	$(9)	(3)%	$(33)	(5)%
Non-cash commodity derivative mark-to-market	$(42)	$16	$(28)	$47	$(58)	*	$(75)	*
Natural gas wellhead (MMcf/d) (c)	4,797	4,483	4,632	4,532	314	7 %	100	2 %
NGL gross production (MBbls/d) (c)	426	366	405	359	60	16 %	46	13 %

* 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 June 30, 2018 vs. Three Months Ended June 30, 2017

Total Operating Revenues — Total operating revenues increased $45 million in 2018 compared to 2017, primarily as a result of the following:

- $78 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;
- $74 million increase primarily as a result of higher volumes due to growth projects primarily related to our DJ Basin system in the North region, increased drilling activity in our Eagle Ford system in the South region and increased volumes and better operational performance in our Midcontinent region, partially offset by the sale of our Douglas gathering system in June 2017, lower volumes due to operational factors in the Permian region and $44 million due to the implementation of ASC 606, and;

These increases were partially offset by:

- $80 million decrease as a result of commodity derivative activity attributable to a increase in unrealized commodity derivative losses of $58 million and a $22 million increase in realized cash settlement losses 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 $54 million in 2018 compared to 2017 as a result of increased gas and NGL sales volumes in our North, Midcontinent and South regions and higher NGL and crude prices, partially offset by lower volumes in our Permian region and 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, partially offset by the sale of our Douglas gathering system in June 2017 in our North region.

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

Other Expense — Other expense in 2017 represents the write-off of property, plant and equipment.

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. We expect the volume declines from these wells to impact future earnings.

Segment Gross Margin — Segment gross margin decreased $9 million in 2018 compared to 2017, primarily as a result of the following:

- $80 million decrease as a result of commodity derivative activity as discussed above;
- $5 million decrease primarily as a result of lower volumes due to operational factors in the Permian region; and
- $3 million decrease primarily as a result of the sale of our Douglas gathering system in June 2017;

These decreases were partially offset by:

- $50 million increase as a result of increased volumes from 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; and
- $29 million increase as a result of higher commodity prices.

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 in the South region (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) ethane recoveries in the Midcontinent and Permian regions and (ii) general volume increases due to increased drilling activity in our Eagle Ford system in the South region.

Six Months Ended June 30, 2018 vs. Six Months Ended June 30, 2017

Total Operating Revenues — Total operating revenues decreased $28 million in 2018 compared to 2017, primarily as a result of the following:

- $99 million decrease as a result of commodity derivative activity attributable to an increase in unrealized commodity derivative losses of $75 million and a $24 million increase in realized cash settlement losses due to movements in forward prices of commodities in 2018;
- $70 million decrease in transportation, processing and other primarily related to the implementation of ASC 606, and;
- $11 million decrease primarily as a result of lower volumes due to operational factors and weather impacting operations in the Permian region;

These decreases were partially offset by:

- $109 million increase primarily as a result of higher volumes due to growth projects primarily related to our DJ Basin system in the North region, increased drilling activity in our Eagle Ford system in the South region and increased volumes and better operational performance in our Midcontinent region, partially offset by the sale of our Douglas gathering system in June 2017, a specific producer arrangement in our North region and $75 million due to the implementation of ASC 606; and
- $43 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.

Purchases and Related Costs — Purchases and related costs increased $5 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 volumes in our Permian region and lower natural gas prices.

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

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. We expect the volume declines from these wells to impact future earnings.

Segment Gross Margin — Segment gross margin decreased $33 million in 2018 compared to 2017, primarily as a result of the following:

- $99 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
- $14 million decrease primarily as a result of lower volumes due to operational factors and weather impacting operations in the Permian region;

These decreases were partially offset by:

- $65 million increase as a result of increased volume from 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; and
- $30 million increase as a result of higher commodity prices.

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 in the South region (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) ethane recoveries in the Midcontinent and Permian regions, and (ii) general volume increases due to increased drilling activity in the South region.

Results of Operations — Logistics and Marketing Segment

Operating Data

System	Approximate System Length (Miles)	Fractionators	Approximate Throughput Capacity (MBbls/d) (a)	Three Months Ended June 30, 2018 Pipeline Throughput (MBbls/d) (a)	Three Months Ended June 30, 2018 Fractionator Throughput (MBbls/d) (a)	Six Months Ended June 30, 2018 Pipeline Throughput (MBbls/d) (a)	Six Months Ended June 30, 2018 Fractionator Throughput (MBbls/d) (a)
Sand Hills pipeline	1,300	—	277	277	—	258	—
Southern Hills pipeline	950	—	117	88	—	82	—
Front Range pipeline	450	—	50	43	—	40	—
Texas Express pipeline	600	—	28	21	—	18	—
Other NGL pipelines (a)	1,200	—	241	163	—	157	—
Mont Belvieu fractionators	—	2	60	—	54	—	58
Total	4,500	2	773	592	54	555	58

(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 June 30,		Six Months Ended June 30,		Variance Three Months 2018 vs. 2017		Variance Six 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	$2,177	$1,732	$4,186	$3,633	$445	26 %	$553	15 %
Transportation, processing and other	16	16	30	33	—	*	(3)	(9)%
Trading and marketing (losses) gains, net	(1)	8	(45)	17	(9)	*	(62)	*
Total operating revenues	2,192	1,756	4,171	3,683	436	25 %	488	13 %
Purchases and related costs	(2,136)	(1,706)	(4,097)	(3,575)	430	25 %	522	15 %
Operating and maintenance expense	(11)	(13)	(22)	(22)	(2)	(15)%	—	— %
Depreciation and amortization expense	(3)	(3)	(6)	(7)	—	— %	(1)	(14)%
General and administrative expense	(3)	(2)	(6)	(5)	1	50 %	1	20 %
Other expense, net	(3)	(2)	(2)	(11)	1	50 %	(9)	(82)%
Earnings from unconsolidated affiliates (a)	94	62	171	116	32	52 %	55	47 %
Segment net income attributable to partners	$130	$92	$209	$179	$38	41 %	$30	17 %
Other data:								
Segment gross margin (b)	$56	$50	$74	$108	$6	12 %	$(34)	(31)%
Non-cash commodity derivative mark-to-market	$5	$8	$(38)	$13	(3)	(38)%	$(51)	*
NGL pipelines throughput (MBbls/d) (c)	592	451	555	439	141	31 %	116	26 %

(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 June 30, 2018 vs. Three Months Ended June 30, 2017

Total Operating Revenues — Total operating revenues increased $436 million in 2018 compared to 2017, primarily as a result of the following:

- $288 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;
- $157 million increase attributable to higher gas and NGL sales volumes, which impacted both sales and purchases, offset by $44 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 decrease in unrealized commodity derivative gains of $3 million and a $6 million increase in realized cash settlement losses due to movements in forward prices of commodities in 2018;

Purchases and Related Costs — Purchases and related costs increased $430 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.

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 accelerated recognition of revenues at Texas Express.

Segment Gross Margin — Segment gross margin increased $6 million in 2018 compared to 2017, primarily as a result of the following:

- $12 million increase in gas marketing due to favorable commodity spreads;
- $2 million increase as a result of higher margins and pipeline throughput, and;
- $1 million increase as a result of higher NGL marketing margins;

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.

Six Months Ended June 30, 2018 vs. Six Months Ended June 30, 2017

Total Operating Revenues — Total operating revenues increased $488 million in 2018 compared to 2017, primarily as a result of the following:

- $398 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;
- $155 million increase attributable to higher gas and NGL sales volumes, which impacted both sales and purchases, offset by $75 million due to the implementation of ASC 606;

These increases were partially offset by:

- $62 million decrease as a result of commodity derivative activity attributable to an increase in unrealized commodity derivative losses of $51 million and a $11 million increase in realized cash settlement losses due to movements in forward prices of commodities in 2018;
- $3 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 $522 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.

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 and accelerated recognition of revenues at Texas Express.

Segment Gross Margin — Segment gross margin decreased $34 million in 2018 compared to 2017, primarily as a result of the following:

- $62 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;

- $30 million increase in gas marketing 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 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.

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 expect to use 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 June 30, 2018, we had $125 million of outstanding borrowings on the revolving credit facility under the Credit Agreement. We had unused borrowing capacity of $1,250 million, net of $25 million of letters of credit, under the Credit Agreement and the financial covenants set forth in the Credit Agreement limit the Partnership's ability to incur incremental debt by this amount as of June 30, 2018. Our cost of borrowing under the Credit Agreement is determined by a ratings-based pricing grid. As of August 3, 2018, we had approximately $1,387 million of unused borrowing capacity under the

Credit Agreement, net of $13 million of letters of credit.
Issuance of Units — On May 11, 2018, we issued 6,000,000 of our Series B Preferred Units representing limited partnership interests at a price of $25 per unit. On June 4, 2018, we issued an additional 450,000 Series B Preferred Units which represented the partial exercise of the underwriters' option to purchase additional Series B Preferred Units. We used the net proceeds of $155 million from the issuance of the Series B Preferred Units for general partnership purposes including funding capital expenditures and the repayment of outstanding indebtedness under our revolving credit facility.
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 six months ended June 30, 2018, we issued our Series B Preferred Units under this registration statement.
In August 2017, we filed a shelf registration statement with the SEC which allows us to issue up to $750 million in common units pursuant to our at-the-market program. During the six months ended June 30, 2018, we issued no 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, 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 $605 million and $166 million as of June 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 $96 million and $46 million as of June 30, 2018 and December 31, 2017, respectively.
As of June 30, 2018, we had $4 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:

	Six Months Ended June 30,	
	2018	2017
	(millions)	
Net cash provided by operating activities	$331	$360
Net cash used in investing activities	$(391)	$(71)
Net cash used in financing activities	$(92)	$(39)

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Six Months Ended June 30, 2018 vs. Six Months Ended June 30, 2017

Operating Activities - Net cash provided by operating activities decreased $29 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 $2 million more of cash distributions in excess of earnings from unconsolidated affiliates during the six months ended June 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 Activities - Net cash used in investing activities increased $320 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 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 increased $53 million in 2018 compared to the same period in 2017 primarily as a result of 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, distributions paid to Series A preferred limited partners, partially offset by net proceeds from long-term debt and proceeds from the issuance of Series B preferred limited partner units. 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 $650 million and $750 million associated with approved projects. We forecast expansion spending to be at the high end of the range. 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 six months ended June 30, 2018 and 2017:

	Six Months Ended June 30, 2018			Six Months Ended June 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	$49	$ 223	$ 272	$44	$ 113	$ 157
Noncontrolling interest portion and reimbursable projects (a)	(2)	(2)	(4)	1	1	2

Total	$47	$ 221	$ 268	$45	$ 114	$ 159

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(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 $126 million and $41 million during the six months ended June 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 $349 million and $256 million during the six months ended June 30, 2018 and 2017, respectively. Distributions paid during the six months ended June 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 six months ended June 30, 2018, no IDR giveback was withheld from the distribution declared.

In accordance with our amended Partnership Agreement, on July 24, 2018 we declared common unit distributions of $154 million for the three months ended June 30, 2018. On the same date, we declared a quarterly distribution on our Series B preferred units of $4 million. We expect to continue to use cash provided by operating activities for the payment of distributions to our common and preferred unitholders, and general partner.

Total Contractual Cash Obligations

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

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
	(millions)				
Debt (a)	$7,769	$ 1,033	$ 1,010	$ 1,675	$ 4,051
Operating lease obligations	145	35	58	31	21
Purchase obligations (b)	4,921	1,287	1,108	1,070	1,456
Other long-term liabilities (c)	145	—	14	18	113
Total	$12,980	$ 2,355	$ 2,190	$ 2,794	$ 5,641

(a) Includes interest payments on debt securities that have been issued. These interest payments are $258 million, $410 million, $325 million, and $2,051 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 June 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 June 30, 2018 condensed consolidated balance sheet. The table above excludes non-cash obligations as well as $31 million of Executive Deferred Compensation Plan contributions and $8 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 June 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 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 Preferred Units and Series B Preferred 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:

Reconciliation of Non-GAAP Measures	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
	(millions)			
Reconciliation of net income attributable to partners to gross margin:				
Net income attributable to partners	$61	$88	$123	$189
Interest expense	67	73	134	146
Income tax expense	1	2	2	3
Operating and maintenance expense	185	178	347	345
Depreciation and amortization expense	97	94	191	188
General and administrative expense	70	71	129	133
Other expense, net	3	5	5	15
Earnings from unconsolidated affiliates	(96)	(86)	(174)	(160)
Gain on sale of assets, net	—	(34)	—	(34)
Net income attributable to noncontrolling interests	1	1	2	1
Gross margin	$389	$392	$759	$826
Non-cash commodity derivative mark-to-market (a)	$(37)	$24	$(66)	$60
Reconciliation of segment net income attributable to partners to segment gross margin:				
Gathering and Processing segment:				
Segment net income attributable to partners	$76	$141	$189	$293
Operating and maintenance expense	169	162	317	315
Depreciation and amortization expense	87	86	171	171
General and administrative expense	2	7	6	13
Other expense, net	—	3	3	3
Earnings from unconsolidated affiliates	(2)	(24)	(3)	(44)
Gain on sale of assets, net	—	(34)	—	(34)
Net income attributable to noncontrolling interests	1	1	2	1
Segment gross margin	$333	$342	$685	$718
Non-cash commodity derivative mark-to-market (a)	$(42)	$16	$(28)	$47
Logistics and Marketing segment:				
Segment net income attributable to partners	$130	$92	$209	$179
Operating and maintenance expense	11	13	22	22
Depreciation and amortization expense	3	3	6	7
General and administrative expense	3	2	6	5
Other expense, net	3	2	2	11
Earnings from unconsolidated affiliates	(94)	(62)	(171)	(116)
Segment gross margin	$56	$50	$74	$108
Non-cash commodity derivative mark-to-market (a)	$5	$8	$(38)	$13

(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.

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	Three Months Ended June 30,		Six Months Ended June 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	$76	$141	$189	$293
Non-cash commodity derivative mark-to-market	42	(16)	28	(47)
Depreciation and amortization expense, net of noncontrolling interest	88	86	172	171
Gain on sale of assets, net	—	(34)	—	(34)
Distributions from unconsolidated affiliates, net of earnings	1	(1)	9	4
Other expense	—	3	3	3
Adjusted segment EBITDA	$207	$179	$401	$390
Logistics and Marketing segment:				
Segment net income attributable to partners (a)	$130	$92	$209	$179
Non-cash commodity derivative mark-to-market	(5)	(8)	38	(13)
Depreciation and amortization expense, net of noncontrolling interest	3	3	6	7
Distributions from unconsolidated affiliates, net of earnings	5	16	10	13
Other expense	1	—	—	9
Adjusted segment EBITDA	$134	$103	$263	$195

(a) There were no lower of cost or market adjustments for the three and six months ended June 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 six months ended June 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 August 3, 2018 were as follows:

Commodity Swaps

Period	Commodity	Notional Volume - Short Positions	Reference Price	Price Range
July 2018 — December 2018	NGLs	(25,250) Bbls/d (c)	Mt.Belvieu (b)	$.29-$.98/Gal
January 2019 — December 2019	NGLs	(7,778) Bbls/d (c)	Mt.Belvieu (b)	$.69-$1.00/Gal
April 2018 — February 2019	Crude Oil	(9,608) Bbls/d (c)	NYMEX crude oil futures (a)	$51.26-$65.25/Bbl
March 2019 — February 2020	Crude Oil	(3,412) Bbls/d (c)	NYMEX crude oil futures (a)	$57.12-$65.17/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

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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. However, the level of NGL exports has increased in recent years. We believe that future natural gas prices will be influenced by the severity of winter and summer weather, the level of North American production and drilling activity of exploration and production companies and the balance of trade between imports and exports of liquid natural gas and NGLs. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also reduce North American drilling activity. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would reduce natural gas volumes gathered and processed, but could increase commodity prices, if supply were to fall relative to demand levels.

Natural Gas Storage and Pipeline Asset Based Commodity Derivative Program — Our natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period condensed consolidated statements of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our condensed consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

The following tables set forth additional information about our derivative instruments, used to mitigate a portion of our natural gas price risk associated with our inventory within our natural gas storage operations as of June 30, 2018:
Inventory

Period ended	Commodity	Notional Volume - Long Positions		Fair Value (millions)	Weighted Average Price
June 30, 2018	Natural Gas	6,615,767	MMBtu	$ 18	$2.76/MMBtu

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions		Fair Value (millions)	Price Range
July 2018-October 2018	Natural Gas	(18,522,500)	MMBtu	$ (1)	$2.80-$3.00/MMBtu
July 2018-October 2018	Natural Gas	9,362,500	MMBtu	$ —	$2.87-$2.98/MMBtu

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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 June 30, 2018, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of June 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 June 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 14 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.

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	*	Third Amended and Restated Agreement of Limited Partnership of DCP Midstream, LP dated May 11, 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 May 11, 2018).
4.1	*	Form of Unit Certificate for 7.875% Series B 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 May 11, 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).
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 Annual Report on Form 10-Q of DCP Midstream, LP for the three and six months ended June 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: August 8, 2018	By:	/s/ Wouter T. van Kempen	
		Name:	Wouter T. van Kempen
		Title:	President and Chief Executive Officer (Principal Executive Officer)
Date: August 8, 2018	By:	/s/ Sean P. O'Brien	
		Name:	Sean P. O'Brien
		Title:	Group Vice President and Chief Financial Officer (Principal Financial Officer)